Bonneville Power Administration

Technical Requirements for Interconnection to the BPA Transmission Grid

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Revision 0 of this document is intended for immediate use. If you wish to make comments, please contact Chuck Matthews at 360-619-6668 or e-mail comments to studyrequest@bpa.gov prior to December 15, 2005. If significant comments are received to warrant document revision, this document will be updated at that time.

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TECHNICAL REQUIREMENTS FOR INTERCONNECTION TO THE BONNEVILLE TRANSMISSION GRID
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1. Introduction

The Bonneville Power Administration Transmission Business Line (TBL) has prepared this **Technical Requirements For Interconnection To The BPA Transmission Grid** document to identify technical requirements for connecting transmission lines, loads and generation resources into the BPA Grid. The purpose of these requirements is to assure the safe operation, integrity and reliability of the BPA Grid. Contractual matters, such as costs, ownership, scheduling, and billing are not the focus of this document. Transmission Services are not addressed by this document either. All requests for transmission services must be made independent of the interconnection requests pursuant to the terms of BPA's prevailing transmission tariffs. Please refer to the BPA web site, www.bpa.gov, or contact TBL Account Executive for more information on the interconnection process, business practices, contractual matters or transmission services.

In this document, the terms BPA, BPA Control Area, BPA Grid, TBL, etc. all refer only to the BPA Transmission Business Line (TBL) and transmission system, not to the BPA Power Business Line (PBL). Interconnection proposals from the PBL are handled in the same manner as those from any other Requester. The term 'Requester' describes the utility, developer or other entity that requests a new or modified connection for a line, load or generation resource.

Requests to interconnect generating resources or loads (Projects) are typically submitted by the Requester but may be in conjunction with an interconnecting utility. BPA evaluates and studies each Project individually, as it was described in the request and determines impacts to BPA Grid facilities. Specific interconnection requirements are then provided back to the Requester. In general, costs for integrating the project are borne by the Requester.

Interconnection evaluations and studies may include a preliminary plan of service for physical and communications interconnections.

Physical laws that govern the behavior of electric systems do not recognize boundaries of electric facility ownership. Therefore the electric power systems must be studied, without regard to ownership, to develop a properly designed interconnection. The completed review may include studies of short-circuit fault duties, transient voltages, reactive power requirements, stability requirements, harmonics, safety, operations, maintenance and prudent electric utility practices.

This document also addresses interconnection through another utility that may not result in a direct interconnection to the BPA Grid. Through telemetering and communications interconnections, BPA can incorporate loads, generators or transmission lines into the BPA Control Area. This type of interconnection, which uses dynamic signals and telemetering, may transfer ancillary services from one party to another.

This document is not intended as a design specification or an instruction manual and the information presented is expected to change periodically based on industry events and evolving standards. Technical requirements stated herein are consistent with BPA's current internal practices for system additions and modifications. These requirements are generally consistent with principles and practices of the **North American Electric Reliability Council** (NERC), **Western Electric Coordinating Council** (WECC), **Northwest Power Pool** (NWPP), **Institute of Electrical and Electronics Engineers** (IEEE) and **American National Standards Institute** (ANSI). Standards of the above listed organizations are also subject to change. The most recent version of such standards shall apply to each interconnection request. This document supersedes DOE/BP-3183 *Technical Requirements for the Connection of Transmission Lines and Loads* and DOE/BP-3162 *Technical Requirements for the Interconnection of Generation Resources*. Important terms used in this document are defined in Section 10 - *Definitions*.

2. Scope

These technical requirements generally apply to all new or modified interconnections to the BPA Grid and telemetered control area interconnections. The location and type of the facility, and impacts on the BPA Grid or another utility's system determine the specific requirements. The interconnection must not degrade the safe operation, integrity and reliability of the BPA Grid. The interconnection requirements are intended to protect BPA facilities, but cannot be relied upon to protect the Requester's facilities.

2-A. Applicable Codes, Standards, Criteria and Regulations

To the extent that the codes, standards, criteria and regulations are applicable, the new or modified facilities shall be in compliance with those listed in Section 11.

2-B. Environmental Considerations of the National Environmental Policy Act

Federal law requires that BPA comply with the National Environmental Policy Act (NEPA) [Ref. 1.5]. BPA cannot commit to construction agreements for interconnection until after those requirements are satisfied.

2-C. Safety, Protection, and Reliability

BPA will make the final determination as to whether the BPA facilities are properly protected before an interconnection is energized. The Requester or interconnecting utility is responsible for proper protection of their own equipment and for correcting such problems before facilities are energized or interconnected operation begins. BPA may determine equivalent measures to maintain the safe operation and reliability of the BPA Grid. For most generators and some loads, this will include BPA capability for direct tripping through special protection schemes. In situations where there is direct interconnection with another utility's system, the requirements of that utility also apply.

2-D. Responsibilities

BPA, the Requester and interconnecting utility are each responsible for the planning, design, construction, compliance with applicable statutes, reliability, protection, and safe operation and maintenance of their own facilities unless otherwise identified in the construction, operation and/or maintenance agreements.

2-E. Special Disturbance Studies

BPA uses series and shunt capacitors, shunt reactive devices, high-speed reclosing, single-pole switching and high-speed reactive switching at various locations. These devices and operating modes, as well as other disturbances and imbalances, may cause stress on interconnected facilities. This may include the possibility of electro-mechanical resonance between a generator and the power system, or large angle changes when considering high-speed reclosing. BPA will conduct studies of interconnection impacts to BPA facilities at the Requester's expense. The Requester is solely responsible for any studies necessary to evaluate possible stresses on their equipment and for any corrective actions.

2-F. Cost Estimates

BPA develops cost estimates on a case-by-case basis when asked to perform interconnection studies since each interconnection is different and causes different impacts to BPA facilities.

3. Requesting Interconnection of New Facilities

Interested parties may request interconnection of a transmission line, load or generation facility to the BPA Grid. Inclusion of such facilities within BPA's Control Area may also be requested. For any of these requests, BPA should be contacted as early as possible in the planning process. An interconnection study must be performed to determine the required additions and modifications to BPA's substations, transmission lines, control and communications circuits to accommodate the proposed interconnection.

Requests for transmission services are addressed by BPA's current Open Access Transmission Tariff and are not included in this document.

3-A. Requesting an Interconnection

Requests for new interconnections should be made through a BPA Transmission Account Executive. Requests should be accompanied by connection related information as listed in Section 9, *Information Requirements for Generators* or in Appendix A, *Transmission Lines and Loads Connection Information* and forms. More information about the generation interconnection process and necessary forms are available in BPA business practices found on the BPA web site, www.bpa.gov.

3-B. Interconnection Studies

BPA personnel perform technical studies to determine the feasibility of the interconnection request. The studies required will vary depending upon the type of interconnection requested. These studies can require considerable time and effort, depending on the size of the Project and its potential system impacts.

The studies will investigate the impact on system performance of the interconnecting project. This may include analysis of equipment thermal overloads, voltage stability, transient stability, and short circuit interrupting requirements. Technical issues directly associated with the project, such as voltage regulation, machine dynamics, metering requirements, protective relaying, and substation grounding will also be addressed as required in development of the preferred plan of service.

4. General Requirements

4-A. Safety and Isolating Devices

For an interconnection to the BPA Grid, an isolating device, typically a disconnect switch, shall be provided to physically and visibly isolate the BPA Grid from the connected facilities. The isolation device may be placed in a location other than the Point of Interconnection (POI), by agreement of BPA and affected parties. Safety and operating procedures for the isolating device shall be in compliance with the BPA *Accident Prevention Manual* and the Requester's and interconnecting utility's safety manuals. All switchgear that could energize equipment shall be visibly identified, so that all maintenance crews can be made aware of the potential hazards. The following requirements apply for all isolating devices:

- Must simultaneously open all three phases (gang operated) to the connected facilities.
- Must be accessible by BPA.
- Must be lockable in the open position by BPA.
- Will not be operated without advance notice to affected parties, unless an emergency condition requires that the device be opened to isolate the connected facilities.
- Must be suitable for safe operation under all foreseeable operating conditions.

All work practices involving BPA owned, maintained, and/or operated equipment, must be done in accordance with the principles contained in the BPA *Accident Prevention Manual*, and done at the direction of BPA Dispatchers. BPA personnel may lock the isolating device in the open position and install safety grounds:

- For the protection of maintenance personnel when working on de-energized circuits.
- If the connected facilities or BPA equipment presents a hazardous condition.
- If the connected facilities jeopardize the operation of the BPA Grid.

4-B. Considerations at Point of Interconnection

4-B.1 General Constraints

Connected facilities shall not restrain BPA from taking a transmission line or line section or other equipment out of service for operation and maintenance purposes. The interconnection line and all its components must be designed and installed to be maintainable within BPA's right to maintain.

4-B.2 General Configurations

Connection of new facilities into the transmission system usually falls into one of three categories:

a. Connection into an existing 69 kV to 500 kV bulk power substation, with (depending on the bus configuration) the existing transmission and new connecting lines each terminated into bays containing one or more breakers.

b. Connection into an existing 69 kV to 500 kV transmission line via a tap

c. Connection by looping an existing 69 kV to 500kV transmission line into a new customer or BPA owned substation.

These three categories may include the situation where another utility owns the transmission line or equipment that directly connects to the BPA Grid.

BPA must maintain full operational control of the transmission path. This may include, but not be limited to, SCADA control and monitoring of circuit breakers, disconnects and other equipment in the new substation. Additionally, BPA will retain contractual path rights. Any new equipment shall not degrade the operational capability of the line.

A multi-terminal line is created when the new connection, such as (b) or (c) above, becomes an additional source of real power and fault current beyond the existing sources at the line terminals. A line with three terminals affects BPA's ability to protect, operate, dispatch and maintain the transmission line. BPA determines the feasibility of multi-terminal line connections on a case-by-case basis.

4-B.3 Special Configurations

The following configurations may substantially affect the costs of a particular connection plan, which may result in an alternate POI plan.

a. Connection to Main Grid Transmission Lines and Substations

Main Grid transmission lines include all 500 kV, 345 kV and some lower voltage lines, as defined by BPA's *Reliability Criteria and Standards*. These circuits form the backbone of the Pacific Northwest transmission system and provide the primary means of serving large geographical areas. In general, BPA requires a substation with additional breakers at the POI to maintain reliability and security of the main grid system. Any deviation from this would need to be evaluated on a case by case basis.

b. Connection to 287 kV and 345 kV Lines

BPA can operate its 287 kV and 345 kV transmission lines at either the normal voltage or at 230 kV. Each of these lines are terminated to transformers that can be bypassed for 230 kV operation. BPA reserves the right to operate these lines at 230 kV. If the transformer fails at a terminal, extended 230 kV operation will be required. For continued operation the connected facilities must also be capable of operating at 230 kV.

4-C. Transformer Considerations

4-C.1 New Installations

Transformers connecting to the transmission system where a source of real power flows through the transformer to the BPA high voltage transmission system shall provide a ground source of current on the high voltage side. A YG-Δ or a YG-Δ-YG transformer with the Y-ground connection on the high voltage side can accomplish this. A YG-YG connection is only appropriate if there is a sufficient ground source on the low voltage side and will need to be evaluated by BPA before being permitted. New Δ-YG transformers with the delta connection on the high side are only permitted on radial (feeder) systems with no power flow into the BPA high voltage transmission system.

4-C.2 Existing Installations

Generation or transmission connections to existing Δ-YG transformers used to serve load may require additional system equipment, such as a grounding bank, to provide adequate protection against ungrounded system operation. Relay protection schemes may also be required to ensure immediate disconnection of the power source following disconnection of the transmission system components. BPA will consider these on a case-by-case basis only.

4-D. Other Interconnection Considerations

4-D.1 Existing Equipment

The proposed new connection may cause existing equipment such as transformers, power circuit breakers, disconnect switches, arresters, and transmission lines to exceed their ratings. New connections may require equipment replacement or an alternate plan of service.

4-D.2 System Stability and Reliability

The BPA Grid has been developed with careful consideration for system stability and reliability during disturbances. The type of connection, size of the source or load, breaker configurations, source or load characteristics, and the ability to set protective relays will affect where and how the connection is made. For most generators and some loads, the Requester will also be required to participate in special protection or remedial action schemes (RAS) including automatic tripping or damping of generation or load. Section 6 provides additional information and requirements for RAS schemes.

4-D.3 Control and Protection

BPA coordinates its protective relays and control schemes to provide for personnel safety and equipment protection and to minimize disruption of services during disturbances. New connections usually require the addition or modification of protective relays and/or control schemes, including replacement or modification of equipment at the remote terminal(s). The new protection must be compatible with existing protective relay schemes and present standards. The addition of voltage transformers, current transformers, or pilot scheme (transfer trip) may also be necessary. BPA will supply the Requester with recommended protective relay systems. Should the Requester select a relay system different from standard BPA applications, BPA reserves the right to perform a full set of acceptance tests prior to granting permission to use the selected protection scheme. Requester selected equipment must have interfaces compatible with BPA equipment.

4-D.4 Dispatching for System Operations and Maintenance

BPA operates and maintains its system to provide reliable customer service while meeting the seasonal and daily peak loads even during equipment outages and disturbances. New line and load connections must not restrict timely outage coordination, automatic switching or equipment maintenance scheduling. Preserving reliable service to all BPA customers is essential and may require additional switchgear, equipment redundancy, or bypass capabilities at the POI for acceptable operation of the system.

4-D.5 Atmospheric and Seismic

The effects of windstorms, floods, lightning, elevation, temperature extremes, icing, contamination and earthquakes must be considered in the design and operation of the connected facilities. The Requester is responsible for determining that the appropriate standards, codes, criteria, recommended practices, guides and prudent utility practices are met for equipment that they are installing.

4-D.6 Physical Security

The potential vulnerability of the facility to sabotage or terrorist threat should be factored into the design and operating procedures. The Requester is responsible for determining that the appropriate standards, codes, criteria, recommended practices, guides and prudent utility practices are met for equipment that they are installing.

4-E. Transmission and Substation Facilities

Some new connections to the BPA Grid require that one or more BPA lines (a transmission path) be looped through the Requester's facilities, or sectionalized with the addition of switches. The design and ratings of these facilities shall not restrict the capability of the line(s) and BPA's contractual transmission path rights.

4-E.1 Transmission Line Designs

BPA owned or maintained transmission lines shall be designed such that the requirements of the *BPA Reliability Criteria and Standards* and *Accident Prevention Manual* are met. Among these requirements are the following:

a. The requirements of the NESC C2 and OSHA shall be met.

b. The minimum approach distances shall be designed in accordance with BPA's Accident Prevention Manual.

c. The line shall be designed and sagged to meet or exceed the NESC C2 clearance to ground while operating at 100˚C maximum operating temperature.

d. All new transmission lines connecting to a BPA substation shall have one or more overhead ground wires (OHGW) to provide substation shielding. For transmission lines from 115 kV to 161 kV, the OHGW shall be ½ mile in length. For transmission lines 230 kV and above, the OHGW shall be 1 mile in length. The OHGW shall be insulated from the substation and grounded at the remote point.

e. All 500 kV double-circuit transmission lines shall have one or more OHGW for the entire length of the line. All 500 kV transmission lines east of the Cascade Mountains shall have OHGW. These OHGW are not continuous but are approximately 15-mile segments with a ground connection in the center of each segment.

f. All lines connecting to a BPA substation shall include either rod gaps or surge arresters for substation entrance protection. BPA staff will recommend the appropriate level of entrance protection.

g. Access to all structures shall be provided.

h. Underbuilds to existing BPA transmission line facilities will generally not be allowed. If an underbuild is requested, a special 'pole contract agreement' will have to be negotiated.

4-E.2 Customer Built Substations and Facilities

Customer built substations that interrupt an existing BPA transmission path and customer-built facilities in a BPA substation must meet the requirements of the *BPA Reliability Criteria and Standards* and *Accident Prevention Manual.* A summary of these requirements follows:

a. The facility must be designed to applicable requirements of the NESC C2, NEC, ANSI and IEEE Standards.

b. The site selection must consider environmental aspects, oil containment and fire suppression.

c. Grounding must be in accordance with IEEE Standard 80.

d. Where BPA transmission is considered critical, two sources of station service is required. Exceptions will be considered on a case by case basis.

e. Electrical equipment in the substation must be sized to carry the full current rating of the interrupted transmission path. This includes circuit breakers, disconnect switches, current transformers and all the ancillary equipment that will serve as the continuation of the path during any switching configuration.

4-F. Insulation Coordination

Power system equipment is designed to withstand voltage stresses associated with expected operation. Adding or connecting new facilities can change equipment duty, and may require that equipment be replaced or switchgear, telecommunications, shielding, grounding and/or surge protection be added to control voltage stress to acceptable levels. Interconnection studies include the evaluation of the impact on equipment insulation coordination. BPA may identify additional requirements to maintain an acceptable level of BPA Grid availability, reliability, equipment insulation margins and safety.

Voltage stresses, such as lightning or switching surges, and temporary overvoltages may affect equipment duty. Remedies depend on the equipment capability and the type and magnitude of the stress. In general, stations with equipment operated at 15 kV and above, as well as all transformers and reactors, shall be protected against lightning and switching surges. Typically this includes station shielding against direct lightning strokes, surge arresters on all transformers, reactors, and surge protection with rod gaps (or arresters) on the incoming lines. The following requirements may be necessary to meet the intent of *BPA's Reliability Criteria and Standards*.

4-F.1 Lightning Surges

If the Requester proposes to tap a shielded transmission line, the tap line to the substation must also be shielded. For an unshielded transmission line, the tap line does not typically require shielding beyond that needed for substation entrance. However,

special circumstances such as the length of the tap line may affect shielding requirements.

Lines at voltages of 69 kV and higher that terminate at BPA substations must meet additional shielding and/or surge protection requirements identified in Section 4-E. For certain customer service substations at 230 kV and below, BPA may require only an arrester at the station entrance in lieu of line shielding, or a reduced shielded zone adjacent to the station. These variations depend on the tap line length, the presence of a power circuit breaker on the transmission side of the transformer, and the size of the transformer.

4-F.2 Switching Surges

At voltages below 500 kV, modifications to protect BPA Grid equipment from switching surges are not anticipated. However, the results of the interconnection studies identify the actual needs. At 500 kV, BPA requires that arresters be added to new line terminations at BPA substations.

4-F.3 Temporary Overvoltages

Temporary overvoltages can last from seconds to minutes, and are not characterized as surges. These overvoltages are present during islanding, faults, loss of load, or long-line situations. All new and existing equipment must be capable of withstanding these duties. BPA follows NESC operating procedures such that normal voltages control practices do not cause temporary overvoltage.

4-F.4 Local Islanding

When the connection involves tapping a transmission line, a local island may be created when the breakers at the ends of the transmission line open. This can leave generating resources and any other loads that also are tapped off this line isolated from the power system. Delayed fault clearing, overvoltages, ferroresonance, extended undervoltages and degraded service to other BPA customers can result from this local island condition. Therefore local islands involving BPA transmission facilities are not allowed to persist. Special relays to detect this condition and isolate the local generation from BPA facilities are described in Section 6-B2.

4-F.5 Neutral Shifts

When generation is connected to the low-voltage, grounded wye side of a delta-grounded wye (Δ – YG) transformer, opening the high voltage connection due to fault clearing may cause overvoltages on the high voltage terminal. These high voltages can affect personnel safety and damage equipment. This type of overvoltage is commonly described as a neutral shift and can increase the voltage on the unfaulted phases to as high as 1.73 per unit. At this voltage, the equipment insulation withstand duration can be very short. Several alternative remedies to avoid neutral shift and its potential problems are possible.

a. Effectively Grounded System

Utilize appropriate transformer connections on the high-voltage side to make the system 'effectively grounded'. Effectively grounded is defined as a system $X_0/X_1 \leq 3.0$ and $R_0/X_1 \leq 1.0$. Any of these methods can result in an effectively grounded system that will minimize the risk of damage to surge arresters and other connected equipment. Methods available to obtain an effective ground on the high voltage side of a transformer include the following:

- A transformer with the transmission voltage (BPA) side connected in a YG configuration and low voltage side in a closed Δ.
- A three winding transformer with a closed Δ tertiary winding and both the primary and secondary sides connected YG.
- Installation of a grounding transformer on the high voltage side.

b. Increase Insulation Levels

Size the insulation of equipment connected to the transmission line high-voltage side to be able to withstand the expected amplitude and duration of the neutral shift. This may include equipment at other locations.

c. High Speed Separation

Rapidly separate the back-feed source from the step-up transformer by tripping a breaker, using either remote relay detection with pilot scheme (transfer trip) or local relay detection of the overvoltage condition (See Section 6-B2).

4-G. Substation Grounding

Each substation must have a ground grid that is solidly connected to all metallic structures and other non-energized metallic equipment. This grid shall limit the ground potential gradients to such voltage and current levels that will not endanger the safety of people or damage equipment which are in, or immediately adjacent to, the station under normal and fault conditions. The ground grid size and type are in part based on local soil conditions and available electrical fault current magnitudes. In areas where ground grid voltage rises beyond acceptable and safe limits (for example due to high soil resistivity or limited substation space), grounding rods and grounding wells might be used to reduce the ground grid resistance to acceptable levels.

If a new ground grid is close to another substation, the two ground grids may be isolated or connected. If the ground grids are to be isolated, there must be no metallic ground connections between the two substation ground grids. Cable shields, cable sheaths, station service ground sheaths and overhead transmission shield wires can all inadvertently connect ground grids. Fiber-optic cables are highly preferable for providing telecommunications and control between two substations while maintaining isolated ground grids. If the ground grids are to be interconnected, the interconnecting cables must have sufficient capacity to handle fault currents and control ground grid voltage rises. BPA must approve any connection to a BPA substation ground grid.

New interconnections of transmission lines and/or generation may substantially increase fault current levels at nearby substations. Modifications to the ground grids of existing substations may be necessary to keep grid voltage rises within safe levels. The connection study will determine if modifications are required and the estimated cost.

The ground grid should be designed to applicable ANSI and IEEE Standards relating to safety in substation grounding [Ref.2.1, 2.2, 2.4, 2.7, 2.9].

4-H. Inspection, Test, Calibration and Maintenance

Transmission elements (e.g. lines, line rights of way, transformers, circuit breakers, control and protection equipment, metering, and telecommunications) that are part of the proposed connection and could affect the reliability of the BPA Grid need to be inspected and maintained in conformance with regional standards. The Requester has full responsibility for the inspection, testing, calibration, and maintenance of their equipment, up to the location of change of ownership or POI. Transmission Maintenance and Inspection Plan (TMIP) requirements are a portion of the WECC Reliability Management System for Transmission. The Requester or utility may be required by WECC to annually certify that it has developed, documented, and implemented an adequate TMIP.

4-H.1 Pre-energization Inspection and Testing

The Requester is responsible for the pre-energization and testing of their equipment. Section 6-D describes specific installation testing requirements for protections systems.

For equipment that can impact the BPA Grid, the Requester shall develop an Inspection and Test Plan for pre-energization and energization testing. BPA may request to review the test plan prior to the test(s). BPA may require additional tests. The Requester shall make available to BPA, upon request, all drawings, specifications, and test records of the POI equipment. Also upon request BPA will make available to the Requester similar documents describing the BPA POI equipment.

4-H.2 Summary of the WECC Transmission Maintenance and Inspection Plan (TMIP)

WECC requires that member utilities prepare a written description of, and update as necessary, its annual TMIP. The TMIP shall provide descriptions of the various maintenance activities, schedules and condition triggers for performing the maintenance, and samples of any checklist, forms, or reports used for maintenance activities. The TMIP may be performance-based, time-based, or both, as may be appropriate. The TMIP shall address each of the following:

- Include the interval schedule (e.g., every two years) for any time-based maintenance activities and a description of conditions that will initiate any performance-based activities.
- Describe the maintenance and inspection methods including specific details for each activity or component listed below in Sections (a) and (b).
- Provide any checklists, forms, or reports used for maintenance activities.
- Where appropriate, provide criteria to be used to assess the condition of a transmission facility or component.
- Where appropriate, specify condition assessment criteria and the requisite response to each condition as may be appropriate for each specific type of component or feature of the transmission facilities.

a. Transmission Line Maintenance

The TMIP shall, at a minimum, describe the maintenance practices for all applicable transmission line activities, including the following:

- Patrols and inspections
- Vegetation management and right-of-way maintenance
- Contamination control (insulator washing)

b. Station Maintenance

The TMIP shall describe the maintenance practices for all applicable station facilities:

- Circuit breakers
- Power transformers and phase-shifting transformers
- Reactive devices (including, but not limited to, shunt capacitors, series capacitors, synchronous condensers, shunt reactors, and tertiary reactors)
- Regulators
- Protective relay systems and associated communication equipment
- Remedial Action schemes and associated communication equipment

c. Maintenance Record Keeping and Reporting

Maintenance records of all maintenance and inspection activities shall be retained for at least five years. The records of maintenance and inspection activities shall be made available to the WECC or other regulatory body, as requested, to demonstrate compliance with the TMIP. The transmission owner shall maintain and make available on request, records for substantial maintenance or inspection of the items listed in Sections (a) and (b) above.

The maintenance and inspection records shall, at a minimum:

- Identify the person(s) responsible for performing the work or inspection
- Indicate the date(s) the work or inspection was performed
- Identify the transmission facility
- Describe the inspection or maintenance that was performed

4-H.3 Calibration and Maintenance of Revenue and Interchange Metering

Revenue and interchange metering will be calibrated at least every two years. Other calibration intervals may be negotiated. All interested parties or their representatives may witness the calibration test. Calibration records shall be made available to all interested parties.

Each meter shall be calibrated against a standard or reference instrument or meter that has been calibrated and certified during the preceding twelve months. Calibration of standard meters and instruments must meet accuracy requirements of the National Institute of Standards and Technology.

4-I. Station Service

Power that is provided for local use at a substation to operate lighting, heat and auxiliary equipment is termed station service. Alternate station service is a backup source of power, used only in emergency situations or during maintenance when primary station service is not available.

Station service power is the responsibility of the Requester. The station service requirements of the new facilities, including voltage and reactive requirements, shall not impose operating restrictions on the BPA Grid beyond those specified in applicable NERC, WECC and NWPP *Reliability Criteria*.

Appropriate providers of station service and alternate station service are determined during the interconnection study and planning process, including Project Requirements Diagram development and review. Generally, the local utility will be the preferred provider of primary station service unless it is unable to serve the load, is prohibitively expensive.

The Requester must provide metering for station service and alternate station service, as specified by the metering section of this document or negotiate other acceptable arrangements.

4-J. Ancillary Services

All loads and transmission facilities must be part of a control area. The control area provides critical ancillary services, including load regulation, and frequency response, operating reserves, voltage control from generating resources, scheduling, system controls and dispatching service, as defined by FERC, or their successors. All new connections to the BPA Grid also require a transmission contract. The Requester must choose the control area in which the new facilities will be located and the source or provider of ancillary services. This election should be identified in the ancillary service exhibit of the transmission contract.

Of particular importance is the Requester's selection of the source for regulating and contingency reserves, if needed. BPA will then determine the telemetering, controls, and metering that will be required to integrate the load or facility into the chosen control area and to provide the necessary ancillary services. If the Requester chooses a self-provision or a third party provision of reserves, then special certification and deployment procedures must be incorporated into the BPA automatic generation control, (AGC) system. The provision of the required ancillary services must meet all relevant NERC, WECC and NWPP reliability policies and criteria.

Normally, the generator will operate in voltage control mode, regulating the voltage to a BPA provided schedule. Typically the generator should supply reactive power for its station service loads and reactive power losses up to the POI. Generator projects may be requested to supply reactive power as an ancillary service.

Normally, the generator will operate its governor to respond independently for frequency deviations. If the governor is controlled through the plant central controller, the governor shall be in 'droop control' mode. Droop setting and performance shall comply with NERC and WECC reliability standards.

5. Performance Requirements

5-A. System Operation and Power Quality

5-A.1 Isolating

The Requester shall not energize any de-energized BPA equipment unless the BPA Dispatcher specifically approves the energization. Where the connection is to a radial load the circuit may be interrupted and reclosed by BPA. In cases where the interconnection breaks an existing BPA line, an autoisolation scheme may be required to maintain continuity to the BPA line. If the interconnected facilities are networked or looped back to the BPA Grid or where generation resources are present, a switching device must open to eliminate fault contributions or neutral shifts. Once open, the device must not reclose until approved by the BPA Dispatcher or as specified in the interconnection agreement.

5-A.2 Synchronizing

The Requester's system or portion of system with energized generators must synchronize its equipment to the BPA Grid. The exception to this is under large-scale islanding conditions, where the BPA Grid will re-synchronize to neighboring systems over major interties. Automatic synchronization shall be supervised by a synchronizing check relay, IEEE Device 25. Please refer to Section 6-D.2, for specific requirements regarding synchronizing and reclosing.

5-A.3 Voltage Schedules

Voltage schedules are necessary, in order to maintain optimal voltage profiles across the transmission system. Optimal profiles minimize transmission of reactive power, and preserve flexibility in use of reactive-power control facilities. To this end, a voltage schedule will be mutually developed between BPA and the Requester, which will be coordinated via time changes developed by the NWPP for such coordination purposes. BPA maintains voltages according to the ANSI Standard C84.1. This allows for variances of ±5% from nominal for all voltage levels except the 500 kV system. The 500 kV system has a nominal voltage of 525 kV with a variance from 500 kV to 550 kV. Limitations of equipment connected to the BPA Grid must not restrict this range of operation. Deviations from the voltage schedule may be ordered by the BPA Dispatcher. Usually the deviations are due to load changes occurring earlier than the NWPP coordinated schedule.

5-A.4 Reactive Power

Each entity shall provide for its own reactive power requirements, at both leading and lagging power factors unless otherwise specified by BPA. BPA generally requires customers to minimize exchange of reactive power with BPA's system, especially under peak load conditions. This can be accomplished by installing equipment to allow matching of internal supply and demand of reactive power. Closely coupled generators may also receive telemetered voltage schedules to minimize var conflict. (See Section 7) Minimizing flow of reactive power on a given line can increase its transfer capability and reduce its losses. Reactive flows at interchange points between control areas should be kept at a minimum as per the *WECC Minimum Operating Reliability Criteria.*

5-A.5 Power Quality

Power quality is the responsibility of both the end users (loads and generation) connected to a utility system and the utilities providing distribution and transmission. Since this document focuses on the interconnection of loads and generation to the BPA Grid, this section will deal primarily with power quality problems typically introduced by the end user or Requester as termed in this document. The Requester is expected to address, in the design of their facilities, potential sources and mitigation of power quality degradation prior to interconnection. Design considerations should include applicable standards including, but not limited to IEEE Standards 142, 519, 1100 1159, 1547, and ANSI C84.1.

In general, the Requester has the responsibility not to degrade the voltage of the utility (BPA Grid) serving other users by requiring nonlinear currents from the grid. The Requesters also have certain responsibilities to account for transmission system events like switching transients and fault induced voltage sags. Standards exist for manufacturers and system designers to take into account short duration system events in order to design equipment or systems with sensitivities capable of riding through events that are within utility system operating standards. If it is determined that the new connection facility is causing a power quality problem, then the Requester will be held responsible for installation of the necessary equipment or operational measures to mitigate the problem. Typical forms of power quality degradation include, but are not limited to voltage regulation/unbalance, harmonic distortion, flicker, voltage sags/interruptions, and transients. Some of the more common forms of degradation are discussed below.

a. Voltage Fluctuations and Flicker

Voltage fluctuations may be noticeable as visual lighting variations (flicker) and can damage or disrupt the operation of electronic equipment. IEEE Standard 519 provides definitions and limits on acceptable levels of voltage fluctuation. Loads or system connections to the BPA Grid shall comply with the limits set by IEEE 519.

b. Harmonic Distortion

Nonlinear devices such as adjustable or variable speed drives (ASD/VSD), power converters, arc furnaces, and saturated transformers can generate harmonic voltages and currents on the transmission system. These harmonics can cause telecommunication interference, increase thermal heating in transformers and reactors, disable or cause misoperations of solid-state equipment and create resonant overvoltages. In order to protect power system equipment from damage or misoperations, harmonics must be managed and mitigated. The new connection shall not introduce harmonics into the BPA Grid in excess of the limits specified in IEEE Standard 519.

In addition to loads with nonlinear devices new generation resources or Distributed Resources should be evaluated not only for possible injected harmonics, but also for potential resonant conditions. For example, some generation resources, whether due to power factor correction capacitors or cable capacitances, may be capacitive during certain operating configurations. These types of configurations may result in resonant conditions within the project or in combination with the utility system. The short circuit ratio (SCR) tests as listed in IEEE 1547 and IEEE 519 can be good indicators of this potential problem. If the evaluation of the new connection indicates potential harmonic resonance the requester may be required to filter, detune, or mitigate in some way the potential resonant conditions associated with connection of the new resource.

For individual end users, the IEEE 519 Standard limits the level of harmonic currents injected at the POI (listed in IEEE as the PCC) between the end user and the utility. Recommended limits are provided for individual harmonic components and for the total demand distortion. These limits are expressed as a percentage of the customer's demand current level, rather than as a percentage of the fundamental, in order to provide a basis for evaluation over time. There are also limits for voltage distortion for both individual frequency and total harmonic distortion.

c. Phase Unbalance

Unbalanced phase voltages and currents can affect coordination of protective relaying, induce higher flows of current on neutral connections, and cause thermal overloading of transformers. A phase unbalance is measured as a percent deviation of one phase from the average of all three phases. To protect equipment owned by BPA and by the Requester, the contribution from the new facilities at the POI shall not be allowed to cause a voltage unbalance greater than 1% or a current unbalance greater than 5%.

System problems such as a blown transformer fuse or open conductor on a transmission system can result in extended periods of phase unbalance. It is the Requester's responsibility to protect all of its connected equipment from damage that could result from such an unbalanced condition.

5-B. Reliability and Availability

5-B.1 Maintaining Service

Reliable operation of the interconnected power system requires the following: reactive sources, control of real and reactive generation, adequate real and reactive reserves and maintenance of transmission systems voltages.

5-B.2 Transmission Lines

The Requestor's facilities may be part of or connected to key transmission lines that must be kept in service as much as possible. They may be removed from service only after power flow studies, in accordance with WECC requirements, indicate that system reliability will not be degraded below acceptable levels. The entity responsible for operating such transmission line(s) shall promptly notify other affected control areas, per the WECC Procedure for *Coordination of Scheduled Outages and Notification of Forced*

Outages, *"Dispatcher/System Operator Handbook"* when removing such facilities from and returning them back to service.

5-B.3 Switchable Devices

Devices frequently switched to regulate transmission voltage and reactive power shall be switchable without de-energizing other facilities. Switches designed for sectionalizing, loop switching, or line dropping shall be capable of performing their duty under heavy load and maximum operating voltage conditions.

5-B.4 Frequency and Duration of Outages

Planned outages of significant system equipment shall be coordinated with all affected parties to minimize their impact on the remaining system. The operator of the Requester's facilities should respond promptly to automatic and forced outages in order to mitigate any impacts on the remaining system, and in a manner that treats all interruptions with the same priority.

5-B.5 Key Reliability and Availability Considerations

a. The new connection shall meet the NWPP, NERC, WECC, and BPA *Planning Standards* as well as respective NERC *Operating Policies,* WECC *Minimum Operating Reliability Criteria* (MORC), and any other WECC guides or policies that apply.

b. Tools and spare equipment must be readily available to accomplish operations and maintenance tasks.

c. Bypass equipment must be fully rated to allow continued operation without creating a bottleneck. Alternate feeds, when provided, shall have sufficient rating to not restrict operation of the BPA Grid.

d. Shielding and electromagnetic interference (EMI) protection shall be provided to insure personnel safety and proper equipment functioning during disturbances such as faults and transients.

e. Standardized design, planning, operating practices and procedures should be used so the new connection may be readily incorporated into the existing transmission network.

f. For reliable operation, the telecommunications, control and protection equipment must be redundant to the extent described in Sections 6 and 8.

g. The equipment for the new connection shall have sufficient capabilities for both the initial operation and for long-range plans.

h. Operations and maintenance personnel must be properly trained for both normal and emergency conditions

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5-C. Power System Disturbances and Emergency Conditions

5-C.1 Minimizing Disturbances

The new facilities shall be designed, constructed, operated, and maintained in conformance with this document, applicable laws and regulations, and standards to minimize the impact of the following:

- Electric disturbances that produce abnormal power flows
- Power system faults or equipment failures

- Overvoltages during ground faults
- Audible noise, radio, television, and telephone interference
- Power system harmonics
- Other disturbances that might degrade the reliability of the interconnected BPA Grid

5-C.2 System Frequency During Disturbances

Power system disturbances initiated by system events such as faults and forced equipment outages, expose the system to oscillations in voltage and frequency. It is important that lines remain in service for dynamic oscillations that are stable and damped.

Large-scale blackouts can result from the excessive loss of generation, outage of a major transmission facility, or rejection of load during a disturbance. In order to prevent such events, under frequency load shedding (UFLS) has been implemented throughout WECC, including the Pacific Northwest. When system frequency declines, discrete blocks of load are automatically interrupted by frequency relays, with most of the interruptions initiated between 59.3 Hz and 58.6 Hz. Load shedding attempts to stabilize the system by balancing the generation and load. It is important that lines and generators remain connected to the system during frequency excursions, both to limit the amount of load shedding required and to help the system avoid a complete collapse. The limited ability of some generators to withstand off-nominal frequency operation has been taken into account in the development of frequency relay setting delays provided on Section 6-D.3.

5-C.3 Voltages During Disturbances

In order to prevent voltage collapse in certain areas of the Pacific Northwest, undervoltage load shedding (UVLS) has also been implemented. Most of the load interruptions will occur automatically near 0.9 per unit voltage after delays ranging from 3.5 to 8.0 seconds. Depending on the type and location of any new load, the Requester may be required to participate in this scheme. The undervoltage relay settings in Section 6-D.3 shall coordinate with the undervoltage load shedding program.

5-C.4 Local Islands

For those generators interconnected to the BPA Grid through a tapped transmission line, a local island is created when the breakers at the ends of the transmission line open. This leaves the generator and any other loads that also are tapped off this line isolated from the power system. Delayed fault clearing, overvoltage, ferroresonance, extended undervoltages, etc., can result from this local island condition and shall not be allowed to persist. Special relays and relay settings are often required to rapidly disconnect the generator(s) in the local island. (See Section 6 *Protection Requirements*.)

5-C.5 Responsibilities During Emergency Conditions

Each control area operator is ultimately responsible for maintaining system frequency within control area boundaries. All emergency operation involving the BPA transmission system must be coordinated with the BPA

Dispatcher. Each party, as appropriate, must participate in any local or regional remedial action schemes. All loads or generators tripped by underfrequency or undervoltage action must not be restored without the control area operator's permission. All schedule cuts need to be promptly coordinated with the appropriate control area operator. All parties have the responsibility for clear communications and to report promptly any suspected problems affecting others.

5-D. Switchgear

5-D.1 General Requirements

Circuit breakers, disconnect switches, and all other current-carrying equipment connected to BPA's transmission facilities shall be capable of carrying normal and emergency load currents, and must also withstand available fault currents without damage. This equipment shall not become a limiting factor, or bottleneck, in the ability to transfer power on the BPA Grid. During prolonged steady-state operation, all such equipment shall be capable of carrying the maximum continuous current that the interconnected facility can reasonably deliver.

All circuit breakers and other fault-interrupting devices shall be capable of safely interrupting fault currents for any fault that they may be required to interrupt. Application shall be in accordance with ANSI/IEEE C37 Standards. These requirements apply to the equipment at the POI as well as other locations on the BPA Grid. BPA supplies the fault-interrupting requirements.

The connection of a transmission line or load can coincidentally include other generating resources. When this system configuration is connected to the low-voltage side of a Δ-YG transformer, the high-voltage side may become ungrounded when remote end breakers open, resulting in high phase-to-ground voltages. This neutral shift phenomenon is described in Section 4-F.5. Switchgear on the high side of a Δ-YG transformer that interrupt faults or load must be capable of withstanding increased recovery voltages.

Circuit breakers shall be capable of performing other duties as required for specific applications. These duties may include capacitive current, and out-of-step switching. Circuit breakers shall perform all required duties without creating transient overvoltages that could damage BPA equipment.

Generally, circuit breakers for transmission lines are required to provide automatic high-speed reclosing, with reclose times ranging from 1/3 of a second to two seconds (20 to 120 cycles). Circuit breakers for 500 kV lines will also typically be required to perform single-pole switching. Resistorless 500 kV breakers on transmission lines will use staggered three-pole closing, in which each phase is closed about one cycle (16 ms) apart.

5-D.2 Circuit Breaker Operating Times

Table 5-1 specifies the interrupting times typically required of circuit breakers on the BPA Grid. These times will generally apply to equipment at or near the POI. System stability considerations may require faster opening times than those listed. Breaker close times are typically four to eight cycles. Circuit breaker interrupting time may vary from those in Table 5-1 but must coordinate with other circuit breakers and protective devices.

Table 5-1 Typical Circuit Breaker Interrupting Times

Voltage Class (kV L-L rms)	Rated Interrupting Time (Cycles)
Below 100 kV	≤ 8
100 kV to 138 kV	≤ 5
161 kV to 230 kV	≤ 3
287 kV to 345 kV	≤ 2
500 kV	≤ 2

5-D.3 Other Fault-Interrupting Devices

Depending on the application, the use of other fault-interrupting devices such as circuit switchers may be allowed. Fuses may be adequate for protecting the high-voltage delta side of a Δ-YG transformer. Trip times of these devices are generally slower, and current-interrupting capabilities are often lower, than those of circuit breakers. These devices must have been tested for the duty in which they are to be applied and they must coordinate with other protective devices operating times. Use of transformer fuses may result in 'single phasing' of low-side connected loads.

5-E. Transformers, Shunt Reactance and Phase Shifters

Transformer tap settings (including those available for under load and no load tap changers), reactive control set points of shunt reactive equipment, and phase shift angles for phase shifters must be coordinated with BPA to optimize both reactive flows and voltage profiles. Automatic controls may be necessary to maintain these profiles on the interconnected system. Timed changes should be coordinated with time schedules established by the NWPP.

Transformer reactance and tap settings for generator transformers should also be coordinated with BPA to optimize the reactive power capability (lagging and leading) that can be provided to the network. Refer to IEEE Standard, C57.116, *Guide for Transformers Directly Connected to Generators* and Standard S2 of the *NERC/WECC Planning Standards in Section III.C.* The continuous reactive-power capability of the generator shall not be restricted by main or auxiliary equipment, control and protection, or operating procedures.

5-F. Generators (General Requirements)

NERC/WECC Planning Standards Sections II.B and III.C must be followed for generator interconnection.

5-F.1 Generator Operation During Emergency System Conditions

The generator, when requested by the BPA Dispatcher during emergency conditions, will be expected to supply reactive power up to its maximum available capability, even if reductions to generation levels are required. Dispatch for non-synchronous sources will be examined on a case-by-case basis, depending upon the performance characteristics of the source and its location within the BPA grid.

5-F.2 Generator Performance During System Disturbances (Swings)

Response to frequency and voltage variances during a system disturbance are defined in Section 6-D.3. Unless otherwise allowed, the generators are to stay connected and operational during such disturbances, up to the limits provided in Section 6-D.3. Deviation from these requirements will be reviewed on a case-by-case basis and may result in additional reserve requirements or other system compensation.

5-F.3 Generator Ride-Through Capability

The generator(s) shall be capable of staying on-line for nearby faults, not including the line connected to or the adjacent buses, for faults cleared assuming the relay and breaker clearing times given in Table 6-1. Deviation from these requirements will be reviewed on a case-by-case basis and may result in additional reserve requirements or other system compensation.

5-F.4 Reactive Power Requirements

Generators shall be designed to maintain a composite power delivery at continuous rated power output at the Point of Interconnection at a power factor within the range of 0.95 leading to 0.95 lagging. The design shall consider the effects of step-up transformer reactance and voltage taps/turns ratios, and bus-fed auxiliary load.

5-G. Asynchronous Generators

5-G.1 Asynchronous Generators With Solid-State Inverters or Double-fed Wound Rotor Induction Generators

These machines shall be operated to provide reactive power similar to that of synchronous generators within the capabilities of the machines. This may include operation on voltage schedules provided by the BPA Dispatchers.

5-G.2 Voltage Control

Voltages at the POI shall not vary more than 0.5% per capacitor switching operation; and shall not deviate more than 3% due to changes in generation output caused by rapid fluctuations in the prime mover speed. The automatic voltage control system shall be fast enough to react to the maximum change in generation anticipated without invoking the operation of system voltage control devices such as shunt capacitors and tap changers. Further, the control system shall be coordinated to minimize operation of customer load regulation equipment including voltage regulators and tap changers. This may typically require the control system to adjust reactive compensation in less than 30 seconds. The alternative may be to require controllable compensation such as static var compensators (SVC).

5-H. Synchronous Generators

5-H.1 Excitation Equipment

Synchronous generator excitation equipment shall follow industry best practice and applicable industry standards. Excitation equipment includes the exciter, automatic voltage regulator, power system stabilizer and over-excitation limiter. Supplementary controls are required to meet BPA transmission voltage schedules.

The following *NERC/WECC Planning Standards* shall be followed. See Section III.C of the standards.

"S1 - All synchronous generators connected to the interconnected transmission systems shall be operated with their excitation system in the automatic voltage control mode unless approved otherwise by the transmission system operator."

(The intent and BPA requirement is that continuous automatic voltage control *not* be overridden by supplementary power factor or reactive power controls that are either part of the automatic voltage regulator or power plant SCADA.)

"S2 - Generators shall maintain a network voltage or reactive power output as required by the transmission system operator within the reactive capability of the units. Generator step-up and auxiliary transformers shall have their tap settings coordinated with the electric system voltage requirements."

"S4 - Voltage regulator controls and limit functions (such as over and under excitation and volts/hertz limiters) shall coordinate with the generator's short duration capabilities and protective relays."

The exciter is normally of the brushless rotating type or the static thyristor type. The excitation system nominal response shall be 2.0 or higher (for definitions see IEEE Standard 421.2). The excitation system nominal response defines combined response time and ceiling voltage. In some cases, the high initial response static type may be required to economically improve power system dynamic performance and transfer capability.

Automatic voltage regulators (AVRs) should be of continuously acting solid-state analog or digital design. Tuning should be in accordance with *NERC/WECC Planning Standard Guide* III.C-G8 reproduced below. Tuning results should be included in commissioning test reports provided to BPA.

"G8 - Generator voltage regulators to extent practical should be tuned for fast response to step changes in terminal voltage or voltage reference. It is preferable to run the step change in voltage tests with the generator not connected to the system so as to eliminate the system effects on the generator voltage. Terminal voltage overshoot should generally not exceed 10% for an open circuit step change in voltage test."

WECC requires that voltage regulators of generating units whose rated output exceeds a certain thresholds, individually or in aggregate, be equipped with a power system stabilizer (PSS). The PSS should be tuned in accordance with WECC guidelines and other industry practices. The 'integral of accelerating power' type of PSS is preferred. Its input can be a speed-related signal derived from terminal voltage and current measurements used in the basic AVR. The PSS can be implemented as a software module within the AVR. BPA recommends that the PSS be included in the procurement specifications as an integral part of the voltage regulator and that tuning be a commissioning requirement.

The voltage regulator shall include an overexcitation limiter. The overexcitation limiter shall be of the 'inverse-time' type, adjusted to coordinate with the generator field circuit time-overcurrent capability. Automatic voltage regulation shall be restored automatically when system conditions allow field current below the continuous rating. BPA may request connection of the voltage regulator line drop compensation circuit to regulate a virtual location 50–80% through the step-up transformer reactance.

The supplementary automatic control is required to adjust the AVR set point to meet the BPA network side voltage schedule. This supplementary control should operate in a 10–30 second time frame, and may also balance reactive power output of the power plant generators.

5-H.2 Governors

NERC/WECC Planning Standard III.C-S5 and guide III.C-G6 apply to governors:

"S5 - Prime mover control (governors) shall operate with appropriate speed/load characteristics to regulate frequency."

"G6 - Prime mover control (governors) should operate freely to regulate frequency. In the absence of Regional requirements for the speed/load control characteristics, governor droop should generally be set at 5% and total governor dead band (intentional plus unintentional) should generally not exceed ±0.06%. These characteristics should in most cases ensure a coordinated and balanced response to grid frequency disturbances. Prime movers operated with valves or gates wide open should control for overspeed/overfrequency."

BPA realizes that some generating facilities will operate at maximum turbine output unless providing frequency control and spinning reserve ancillary services. BPA interprets G6 to require governor controls to be set for 'droop control mode'.

5-I. Generator Performance Testing, Monitoring and Validation

A generator owner is responsible for providing a dynamic model of its generating plant to BPA. The model will characterize plant responses to system disturbances (voltage and frequency deviations at point of interconnection, oscillations) and control signals (power and voltage schedule). The dynamic model will be a part of the power system model used in system studies to determine operating transfer limits and network reinforcements. An incorrect model may result in incorrect transfer limits, which can either put the system at risk of failure or unnecessarily restrict transmission use.

5-I.1 Parametric Testing

Parametric testing is a detailed test performed on a generator to determine parameters of a synchronous machine and its controls, as defined in the WECC test guidelines**.** Parametric testing shall be done for the following equipment:

- Synchronous machines
- Exciter and voltage regulators
- Turbine – governor
- Power System Stabilizer (PSS)
- Over-Excitation Limiter (OEL)

Typical data can not be substituted for actual parametric test data which is required for every generator greater than 10 MW:

- On a new generator during commissioning.
- When the generator or turbine is retrofitted.
- When the generator controls are replaced or retuned.
- When a severe discrepancy is observed in performance validation.

5-I.2 Performance Validation

Performance validation of the generator model is done using measurements recorded during actual disturbances and tests. Recorded generator voltage and frequency are input into the model to verify that simulated real and reactive power responses are in good agreement with the recorded responses. Generator owners shall submit an Evidence of Performance Validation every five years. Performance validation shall include:

- Responses to at least three frequency excursions greater than 0.1 Hz (alternatively 1% speed or 20% power reference steps);

- Responses to at least three voltage changes greater than 2% (alternatively 2% voltage reference steps).

5-I.3 Performance Monitoring

A transmission operator will monitor performance of a generating plant at the Point of Interconnection by taking measurements of bus voltage and frequency, generator current and power, and control signals sent to the generating plant.

Performance monitoring is recommended for use with performance validation. A transmission operator will collect disturbance data and will perform performance validation. If a severe discrepancy is observed, the generator owner shall be required to perform parametric testing of the generation equipment in question. See section 6-G for additional requirements for performance and disturbance monitoring.

5-J. Generator Blackstart Capability

Blackstart is the term describing the startup of a generating plant under local power, isolated from the power system. Blackstart capability is needed in some rare circumstances, depending on the size and location of the generation facility. It is generally not needed for small generators or for projects that are near other major generation. This capability is addressed in the planning and review process, and indicated on the Project Requirements Diagram. Loads that are scheduled and available for blackstarts are selected to avoid the trip-out of generation units by exceeding frequency and voltage set points. By selecting voltage variable loads, avoiding motor start-up loads and imposing block size limits of (50 MW) can accomplish this. During blackstart restoration, the tapped connection must be able to be opened to avoid interference with BPA restoration procedures on the BPA transmission path.

Considerations related to blackstart capability include the following:

1. Proximity to other major generation facilities (i.e. Can startup power be provided more efficiently from an existing plant?)

2. Location on the transmission system (i.e. Is the generation facility near major load centers and far from generation?)

3. Cost of on-site start-up

4. Periodic testing to ensure personnel training and capability.

6. Protection Requirements

6-A. Introduction

The protection requirements identified in this document address the following objectives:

- Ensure the safety of the general public, BPA and other utility personnel.
- Minimize property damage to the general public, BPA, and customers.
- Minimize adverse operating conditions affecting BPA and customers.
- Comply with NERC, WECC and NWPP protection criteria in existence

In order to achieve these objectives, certain protective equipment (relays, circuit breakers, etc) must be installed. These devices ensure that faults or other abnormal conditions the appropriate equipment is promptly disconnected from the BPA Grid. Protective equipment requirements depend on the plan of service. Significant issues that could affect these requirements include:

- The location and configuration of the proposed connection.
- The level of existing service and protection to adjacent facilities (including those of other BPA customers and potentially those of other utilities).
- The connection of a line or load that coincidentally connects a generation resource, which was not previously connected to the BPA Grid. In this case, the Requester will also have to follow the additional requirements for interconnection of generation resources.

BPA will work with the Requester to achieve an installation that meets the Requester's and BPA's requirements.

BPA cannot assume any responsibility for protection of Requester's equipment. Requesters are solely responsible for protecting their equipment in such a manner that faults, imbalances, or other disturbances do not cause damage to their facilities or result in problems with other customers.

6-B. Protection Criteria

The protection system must be designed to reliably detect faults or abnormal system conditions and provide an appropriate means and location to isolate the equipment or system automatically. The protection system must be able to detect power system faults within the protection zone. The protection system should also detect abnormal operating conditions such as equipment failures or open phase conditions. Special relaying practices may also be required for system disturbances, such as undervoltage or underfrequency detection for load shedding or reactive device switching. For most generation and some loads, the Requester will also be required to participate in special protection schemes or RAS including automatic tripping or damping.

6-B.1 General Protection Practices

The following summarizes the general protection practices as required by NERC and WECC, as well as specific practices and applications as applied to BPA transmission lines and interconnections. The protection schemes and equipment necessary to integrate the new connection must be consistent with these practices. Table 6-1 specifies maximum allowable operating times for protection systems and breakers by voltage category.

a. Protection Requirements For All Voltages

1. Relays and circuit breakers, etc. are required at the Point of Interconnection, (POI) or a connecting substation to isolate BPA equipment from the Requester's system during faults.

2. At the POI, the Requester is not allowed to energize a de-energized line connected to the BPA Grid without approval of the BPA Dispatcher.

3. Breaker reclose supervision (automatic and manual including SCADA) may be required at the connecting substation and/or electrically 'adjacent' stations; e.g., hot bus and dead line check, synchronization check, etc.

4. Dual batteries are not required, but each set of relays must have its own separately protected DC source.

5. Relay settings shall not infringe upon BPA's ability to operate at maximum transfer levels, even with system voltages as low as 0.8 per unit (pu).

6. Protection schemes shall be designed with sufficient number of test switches and isolating devices to provide ease of testing and maintenance without the necessity for lifting wires. Isolating switches shall be alarmed or operating and maintenance tagging procedures developed and followed to assure switches are not inadvertently left in an open position.

7. The POI protection system security and dependability and their relative effects on the power system must be carefully weighed when selecting the protection system.

8. BPA reserves the right to review and recommend changes to the protection system and settings for POI protection equipment.

9. If required, automatic underfrequency load tripping total trip time, including relay operating time and breaker operating time, shall not exceed 14 cycles. Any underfrequency load tripping must comply with the WECC and NWPP requirements.

10. Use of capacitive voltage transformers (CVTs) and magnetically coupled voltage transformers (MVTs) are generally acceptable for protection purposes.

11. Use of bushing potential devices for protective relaying may not be appropriate. If the device needs to respond to overvoltages and

frequency deviations, bushing potential devices may not be acceptable.

12. Current transformers used for protective relaying should generally have a C800 accuracy class rating.

13. Total fault-clearing times, with or without a pilot scheme, must be provided for BPA review and concurrence. Breaker operating times, relay makes, types and models, and relay settings must be identified specifically.

14. Generator protection shall meet WECC under/overvoltage and under/over frequency requirements as specified in Section 6-D3.

b. Additional Protection Requirements for Voltages Below 100 kV

1. Redundant or overlapping relay systems are required such that no single protection system component failure would disable the entire relay system and result in the failure to trip for a fault condition.

2. Multi-shot automatic reclosing is allowed for single and multi-phase faults. The total number of automatic recloses should not exceed three.

c. Additional Protection Requirements for Voltages 100 kV and Above

1. Breaker failure relays, (BFR) are required. Total time for BFR scheme fault clearing must not exceed 8 cycles. For three cycle breakers, clearing time may be longer for slower breakers. System requirements may dictate faster BFR operating times. Breaker failure relays need not be redundant.

2. Dual circuit breaker trip coils are required.

3. Redundant relay systems are required if a single point of failure could disable the entire relay system. Both relay systems shall contain an instantaneous trip element with the ability to out put a trip in 1.5 cycles or less, for faults within 80% of the line. If ground distance elements are used, the relay must include ground overcurrent elements to provide tripping for high-resistance ground faults.

4. A pilot telecommunication scheme must be installed for either of the following conditions: 1) high-speed clearing is necessary for any fault location for stability purposes or 2) remote tripping for equipment protection. If a pilot telecommunications scheme is required for stability purposes, it must be redundant or designed to allow high-speed tripping by the protective relays upon failure of the pilot scheme.

5. The relay systems shall provide backup protection for loss of the telecommunication channel(s).

6. The selected pilot schemes and telecommunication system must be compatible with existing BPA protection and telecommunications equipment.

7. The telecommunications and pilot scheme channels required for protection systems should be either continuously monitored, or periodically.

8. Redundant relays shall not be connected to a common current transformer secondary winding.

9. Directional relay systems are required on all non-radial connections.

d. Additional Protection Requirements for Voltages Between 100 kV and 138 kV

1. Automatic reclosing for single line-to-ground faults shall be no faster than 35 cycles.

2. Automatic reclosing is allowed for multiphase faults.

3. Multi-shot automatic reclosing may be required for automatic line sectionalizing schemes. The total number of automatic recloses should not exceed three.

e. Additional Protection Requirements for Voltages Between 161 kV and 345 kV

1. For most lines, total fault clearing time with a pilot scheme must not be more than four cycles, including relay and breaker operating times. Slower times may be acceptable for some lines. Refer to Table 6.1.

2. Automatic reclosing for single line-to-ground faults shall be no faster than 35 cycles and usually no slower than 60 cycles.

3. Automatic reclosing is not allowed for multiphase faults. It is acceptable to block reclosing for time-delayed trips or loss of all pilot channels on the protected line.

f. Additional Requirements for 500 kV (525 kV)

1. Two independent sets of directional line protection with separate pilot telecommunication for each relay set shall be installed at each line terminal to trip the line terminal breakers.

2. Total fault clearing time with a pilot scheme must not be more than four cycles, including relay and breaker time.

3. Line protection may be required to be compatible with existing or planned series compensation.

4. Protection must be able to interface with BPA's single-pole switching schemes.

5. Automatic reclosing shall be no faster than 35 cycles and usually no slower than 60 cycles for standard three-pole or single-pole switching, and no slower than 100 cycles for hybrid single-pole switching.

6. Automatic reclosing is not allowed for multiphase faults. It is acceptable to block reclosing for time-delayed trips or loss of all pilot channels on the protected line.

6-B.2 Protection Measures

Protection systems must be capable of performing their intended function during fault conditions. The magnitude of the fault depends on the fault type, system configuration, and fault location. It may be necessary to perform extensive model line tests of the protective relay system to verify that the selected relay works properly for various system configurations. Power system swings, major system disturbances and islanding may require the application of special protective devices or schemes. The following discussion identifies the conditions under which relay schemes must operate.

a. Phase Fault Detection

The relay system must be able to detect multi-phase faults and trip at high speed for high fault currents. Non-directional overcurrent, directional overcurrent, distance, and line differential relays may be applicable depending on system requirements.

Infeed detection to faults within the power system usually requires directional current-sensing relays to remove the contribution to the fault from the POI. The distance relay (21) is a good choice for this application since it is generally immune to changes in the source impedance.

b. Ground Fault Detection

Ground fault detection has varying requirements. The availability of sufficient zero-sequence current sources and the ground fault resistance both significantly affect the relay's ability to properly detect ground faults. The same types of relays used for phase fault detection are suitable for ground fault detection. If ground fault distance relays are used, backup ground time-overcurrent relays should also be applied to provide protection for the inevitable high-resistance ground fault.

c. Islanding

Islanding describes a condition where the power system splits into isolated load and generation groups, usually when breakers operate for fault clearing or system stability remedial action. Some utilities isolate their distribution system and use local generation to feed loads during power system outages. BPA does not allow islanding conditions to exist that include its facilities, except for a controlled, temporary, area-wide grid separation. Where generation is connected, implications of islanding must be addressed to minimize adverse impacts on connected loads.

During an islanded condition or system disturbance, power swings may result which can affect the operation of protective relays, especially distance relays. Out-of-step blocking is commonly available for distance relays to prevent them from operating during a power swing. However, the application of such schemes must be coordinated with BPA to assure that the blocking of the distance elements will not result in inappropriate or undesirable formation of islands.

d. Relay Performance and Transfer Trip Requirements

Relay systems are designed to isolate the transmission line and/or other facilities from the BPA Grid. However, the performance (clearing time speed) of these local relay systems and the associated isolating devices (circuit breakers, circuit switchers, etc) will vary. The protection equipment of the new connection must, at least maintain the performance level of the existing protection equipment at that location. This may require transfer trip (pilot telecommunications) to insure high-speed and secure fault clearing. Other types of pilot tripping such as directional comparison, phase comparison or current differential may also be acceptable if the scheme chosen can achieve the total clearing times required. Transfer trip is required when any of the following conditions apply to the new connections:

1. Transient or steady-state studies identify conditions where maintaining system stability requires immediate high-speed separation of the POI facility from the power system.

2. Special operational control considerations require immediate separation of the POI from the BPA Grid.

3. Extended fault duration represents an additional safety hazard to personnel and can cause significant damage to power system equipment.

4. Slow clearing or other undesirable conditions such as extended overvoltages or ferroresonance which, cannot be resolved by local conventional protection measures, will require the addition of pilot tripping using remote relay detection at other substation sites. This scenario is a distinct possibility should a BPA circuit that connects other customer loads become part of a ‘local island’ that includes a generator.

5. When remote circuit breaker tripping is required, in order to clear faults in a transformer not terminated by a high side breaker, high-speed transfer tripping will be required. The transfer trip may also be required to block automatic reclosing. Other unique configurations may impose the same requirement.

6. Relay operate times are adjusted to coordinate for faults on the local configuration such as a three terminal lines, fault currents available, etc. Total clearing times must be less than those listed in Table 6-1. Refer to

Section 8-D for telecommunication issues as they pertain to control and protection requirements.

Table 6-1 Relay and Breaker Operating Times by System Voltage

Connection Voltage (Line-Line rms)	Total Clearing Time (Cycles)	Maximum Relay Operate Time (Cycles)	PCB Trip Time (Cycles)	Time Delayed Tripping Acceptable?
< 100 kV	≤ 12-14*	≤ 4-6*	≤ 8	Yes
100 to 138 kV	≤ 7-9*	≤ 2-4*	≤ 5	Yes
161 to 230 kV	≤ 5-7*	≤ 2-4*	≤ 3	Yes
230 kV Main Grid to 345 kV	≤ 4	≤ 1	≤ 2	No**
500 kV	≤ 4	≤ 1	≤ 2	No**

* Relay operating and total clearing times are for instantaneous element trips at the terminal closest to the fault. Inverse time and time delayed elements are considerably longer. Sequential instantaneous or time delay tripping may occur at the remote terminal.

** Transfer trip or other communications aided-tripping is required.

e. Synchronizing and Reclosing

If the connection is made to an existing line, automatic reclosing schemes at the remote line breakers may need to be modified. On transmission lines below 138 kV, automatic-sectionalizing schemes may be installed to isolate a portion of the system that has a permanent fault. This includes multi-shot automatic reclosing at remote terminals. A new interconnection should be compatible with such existing schemes. If the new connection results in the possibility of connecting a generation source, special considerations may be required. Section 6-D identifies protection requirements specifically related to generator additions.

6-C. Protection System Selection and Coordination

6-C.1 Protection Requirements for the Interconnecting System

Upon request, BPA will supply the Requester with a list of protective relay systems considered to be suitable for use at the POI. Should the Requester select a relay system not on our approved list, BPA reserves the right to perform a full set of acceptance tests prior to granting permission to use the selected protection scheme. Alternatively, the relay vendor or a third party may be asked to perform thorough model line tests of the proposed relay system. If there are special performance requirements for the protective relays at the POI, BPA will notify the Requester.

6-C.2 Protection System Coordination and Programming

The following are basic considerations that must be used in determining the settings of the protection systems. Depending upon the complexity and criticality of the system at the POI, complete model line testing of the protection system, including the settings and programming, may have to be performed prior to installation to verify the protection system performance.

a. Fault study models used for determining protection settings should take into account significant zero-sequence impedances. Up-to-date fault study system models shall be used.

b. Protection system applications and settings should not normally limit transmission use.

c. Application of zone 3 relays or other relays with settings overly sensitive to overload or depressed voltage conditions should be avoided where possible.

d. Protection systems should prevent tripping for stable swings on the interconnected transmission system.

e. Protection system applications and settings should be reviewed whenever significant changes in generating sources, transmission facilities, or operating conditions are anticipated.

f. All protection system trip misoperations shall be analyzed for cause, and corrective action taken.

6-C.3 Relays for the Point of Interconnection

The following list of relays has been developed in recognition of varied interconnection requirements. Relay performance under certain fault scenarios is also a consideration in the selection of these relays. The specific relays used must be functionally consistent with and complementary to BPA's general protection practices identified in Section 6-B1.

The relay functions generally necessary to serve this purpose as used by BPA include:

a.	Phase overcurrent (non-directional)	(50/51)
b.	Neutral overcurrent (non-directional)	(50/51-N)
c.	Zone distance (phase or phase and ground distance)	(21/21-N)
d.	Directional ground overcurrent	(67-N)
e.	Ground overcurrent	(51-G)
	or ground fault detection scheme	(59-Z)
f.	Over/under voltage	(59/27)
g.	Over/under frequency	(81)
h.	Instantaneous overvoltage (ungrounded high side)	(59)

i. Remote automatic breaker reclose supervision (HB/DL, HB/HL with synchronism check) (79-X)
j. Current differential (87)

Except as otherwise agreed by BPA, BPA will furnish, install, operate and maintain all relaying at the POI for the purposes of protecting the BPA Grid. Other relaying for protection of the Requester's equipment will be the responsibility of the Requester. All relays, which can adversely affect the BPA Grid, shall be of 'utility grade' quality, subject to review by BPA.

Refer to Section 8-D for telecommunication issues as they pertain to control and protection requirements.

6-D. Generator Protection - Special Requirements

Integration of new generation has special requirements in addition to the previously described protection requirements. This section primarily deals with the protection requirements for the integration of synchronous and induction rotating machines. The actual protection requirements and choice of relay type will vary depending upon several factors:

- MVA capacity of the generation
- Type of generation: synchronous or non-synchronous
- Location of the generation interconnection on the transmission grid
- Voltage level of the generation interconnection
- Transformer winding configuration for the generator step-up transformer and/or interconnecting transformer
- Change in the fault current capacity as a result of the added generation
- Availability of telecommunications facilities

Examples of some typical generator integration plans are shown in Table 6.2 and Figures 6-1 through 6-5. Table 6.2 identifies only the protection equipment, which may affect the operation of the BPA Grid. The type of resource proposed and location of the POI will determine any special protection requirements for other types of resources, such as photovoltaic, tidal, etc.

6-D.1 Fault Protection

Protective relays will be required to detect phase and ground faults on the generator interconnection. The relay systems shown in Figures 6-1 through 6-5 are designed to isolate the generator from the BPA grid at or near the POI. However, the performance (clearing time speed) of these local relay systems and the associated isolating devices (circuit breakers, circuit switches etc.) will vary. In most cases, protective devices described in Section 6-B will also be appropriate for this interconnection.

Ground fault detection has varying requirements. The most significant consideration in the ability to detect ground faults on the BPA Grid is the winding configuration of the transformer connecting the generator to the grid. The scenarios below assume that the generator is connected to the low-voltage side of this transformer.

a. Transformer Grounded Wye (YG) Connection on the BPA Grid Side

This is the BPA required transformer connection when adding a new generation resource to the transmission grid. The transformers will either be YG-Δ or YG-Δ-YG. Either of these connections provides a solid ground source for the transmission grid.

For a transformer connected with a grounded-wye on the primary (high-voltage) side, a ground overcurrent relay (50/51-G) connected in the neutral of the wye winding provides transmission fault detection. This relay also protects the transformer.

A directional ground overcurrent relay (67-N) is generally provided for detection of ground faults in the transmission system when transformer connections are of the types identified above. Since this relay function complements zone-distance protection used for phase fault detections, it is included in many presently manufactured relays. See Figures 6-1, 6-2 and 6-5 for typical examples of this configuration.

b. Transformer Delta (Δ) Connection on the BPA Grid Side and Potential Overvoltages

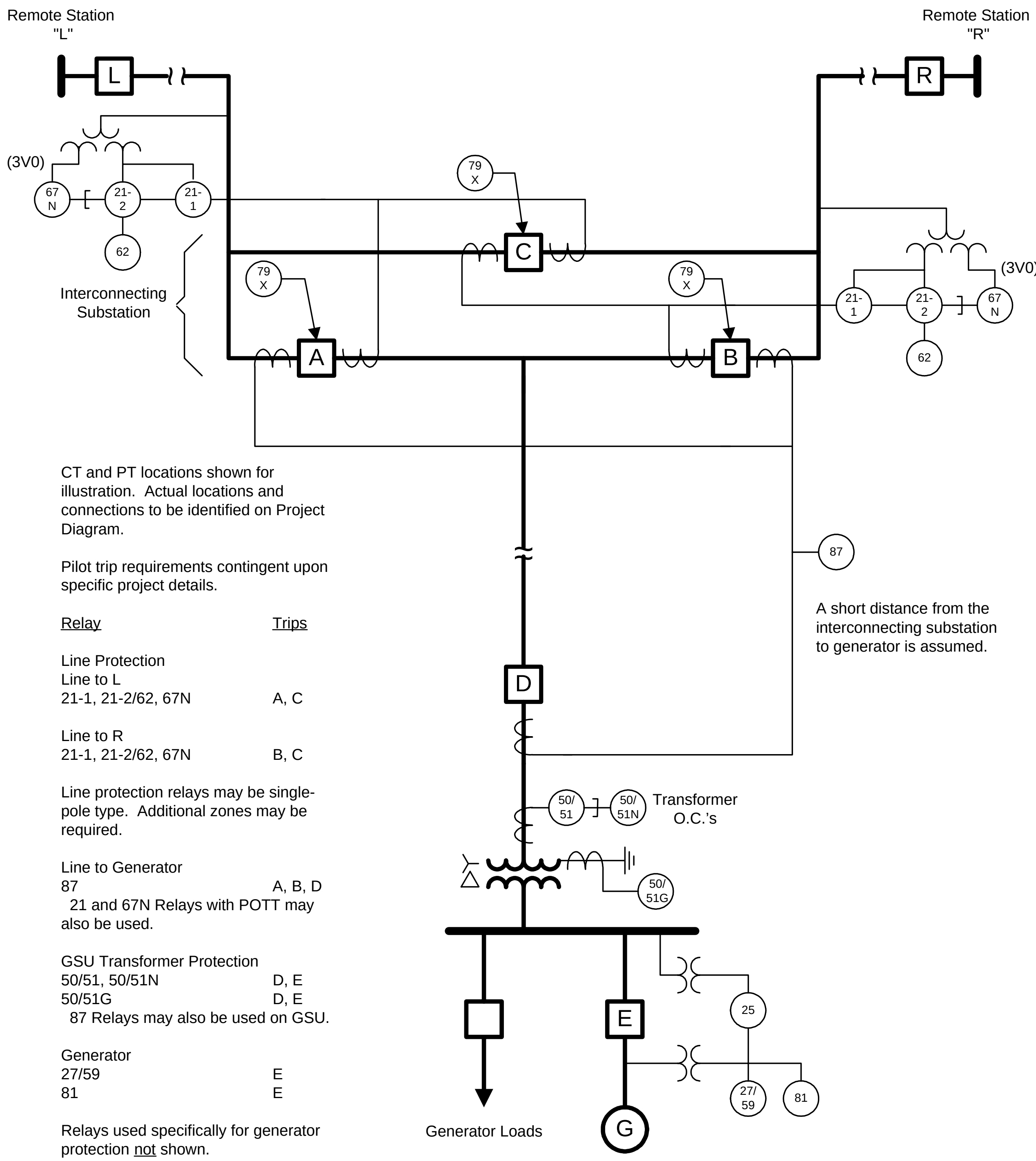
Some smaller generation projects are proposed for integration into existing utility power systems through a delta transformer connection to the transmission grid. This Δ-YG transformer was originally designed only to serve loads; e.g., connection at the 12.5 kV side of the 115 kV/12.5 kV transformer. This common transformer configuration requires special relay considerations when generation is proposed for connection to the low voltage terminal. The existing protection at these installations was applied under the assumption that there was not a source from the low-voltage side to infeed to faults in the power system. BPA will review all such requests on a case-by-case basis to determine acceptability. New relays, transfer trip, ground detection equipment, or a grounding transformer may be required to assure timely removal of the generation source for safe clearing of faults on the transmission system. Figures 6-3 and 6-4 show examples of this configuration.

Table 6-2 Relay Functions for Figures 6-1 to 6-5

Interconnecting Substation, High Voltage Transmission Line Protection		
The following relays are intended for the interconnecting substation to detect faults on the BPA Grid and isolate the interconnecting substation from the BPA Grid.		
Figure	**Relay**	**Intent**
6.1, 6.2, 6.4, 6.5	**21-1, 21-2 / 62**	Distance relays trip line breakers for multi-phase faults on the transmission lines to the Interconnecting Substation. Ground distance relays may be used for ground faults. These relays may have single pole switching capability. They also may be connected to a transfer trip or other pilot channel. More than two zones may be required.
6.1, 6.2, 6.4, 6.5	**67 N**	Directional ground overcurrent relay trips line breakers for ground faults on the transmission lines to the Interconnecting Substation. These relays may have single pole switching capability. They also may be connected to a transfer trip or other pilot channel. Potential polarization: shown in the figures. Current polarizing or negative sequence polarizing may also be used.
6.1, 6.2, 6.4, 6.5	**87**	Line differential relays are often necessary to avoid coordination problems with other relays to limit nuisance trips of the generator. Distance relays (21), directional overcurrent ground relays (67N), and a permissive overreach transfer trip may also be used.
6.1 - 6.5	**79 X**	Automatic reclose supervision is necessary at the interconnecting substation and/or the remote high voltage substations when a generator is added. This includes a hot bus/dead line (HB/DL) check and a synchronism check. The automatic reclose supervision will prevent the transmission line from reclosing if the generator remains in service and is not in synchronism with the BPA Grid.
6.3, 6.4	**59**	This relay detects overvoltages, and ground faults as indicated above. With an instantaneous trip at 1.5pu overvoltage. It is provided to avoid arrester failure for ground faults. This scheme is most often required when the interconnecting substation includes a Δ-YG transformer.
6.3, 6.4	**59 Z**	A ground fault detection scheme is used to detect ground faults on the tapped transmission line. (Normally the open delta 3V0 scheme with inverse time characteristic). Trips of this relay may need to be time coordinated with other relays so that faults beyond the tapped transmission line do not cause unnecessary trips of the generator feeder. This scheme is most often required when the interconnecting substation includes a Δ-YG transformer.

Table 6-2 (cont.) Interconnecting Substation, Transformer Protection		
The following devices are typically used at the interconnecting substation to provide protection of the power transformer that interfaces between the generator and the BPA Grid.		
Figure	**Relay**	**Intent**
6.3	**Fuse**	Some existing Δ-YG transformers may have high side fuse protection. This is generally not acceptable for new installations.
6.1 - 6.5	**50/51, 50/51N**	These relays protect transformers from overcurrent conditions caused by low side faults extreme overloads or unbalances. Phase overcurrent relays are usually set to pickup at approximately twice the transformer thermal rating. These relays are time-coordinated with low side feeder relaying. Voltage restrained time overcurrent relays may be used instead of the standard 50 element. 50/51 relays may also provide backup for transformer 87 relays.
6.1, 6.2, 6.4, 6.5	**50/51G**	This relay protects transformers from overcurrent conditions caused by low side ground faults or extreme unbalances. These relays are time-coordinated with low side feeder relaying.
6.1 - 6.5	**63**	Sudden pressure or Buchholz relays may also be provided for the transformer.
6.1 - 6.5	**87**	Transformer differentials relays may be used for transformer protection.

Table 6-2 (cont.) Generator Interconnection		
The following relays are required at or near the generation. These relays do not provide fault protection for the generator itself, which is the responsibility of the generator owner.		
Figure	**Relay**	**Intent**
6.1 - 6.4	**25**	This relay provides synchronism check supervising function for all closes of generator breakers.
6.1 - 6.5	**27/59**	These relays detect abnormal voltage conditions often caused by islanded operation scenarios. The undervoltage relay can serve as a means of fault detection for instances of weak fault current infeed from generator to faults on the feeder or interconnected system. It protects generator against extended operation at abnormal voltages. Undervoltage relay settings are coordinated with Pacific Northwest undervoltage load shedding plan (Section 6-D.3).
6.1 - 6.5	**81**	This relay detects abnormal frequency conditions, often caused by islanded operation scenarios. It protects generator against extended operation at abnormal frequencies. Underfrequency relay settings are coordinated with the WECC and NWPP underfrequency load-shedding plan (Section 6-D.3).



CT and PT locations shown for illustration. Actual locations and connections to be identified on Project Diagram.

Pilot trip requirements contingent upon specific project details.

<u>Relay</u>	<u>Trips</u>
Line Protection	
Line to L	
21-1, 21-2/62, 67N	A, C
Line to R	
21-1, 21-2/62, 67N	B, C

Line protection relays may be single-pole type. Additional zones may be required.

Line to Generator	
87	A, B, D

21 and 67N Relays with POTT may also be used.

GSU Transformer Protection	
50/51, 50/51N	D, E
50/51G	D, E

87 Relays may also be used on GSU.

Generator	
27/59	E
81	E

Relays used specifically for generator protection <u>not</u> shown.

Figure 6-1

Integration of Generation into a Transmission Level Substation

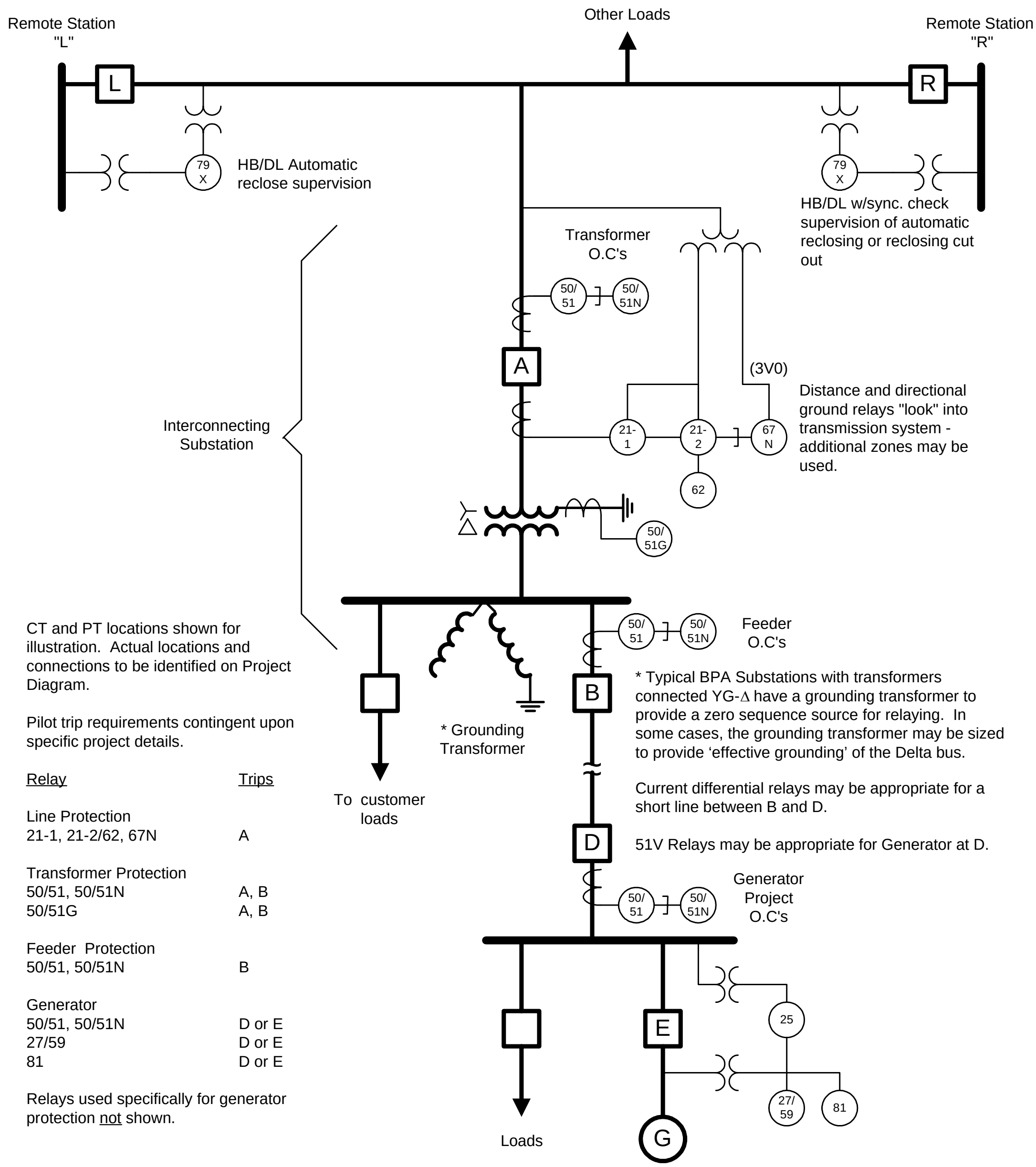
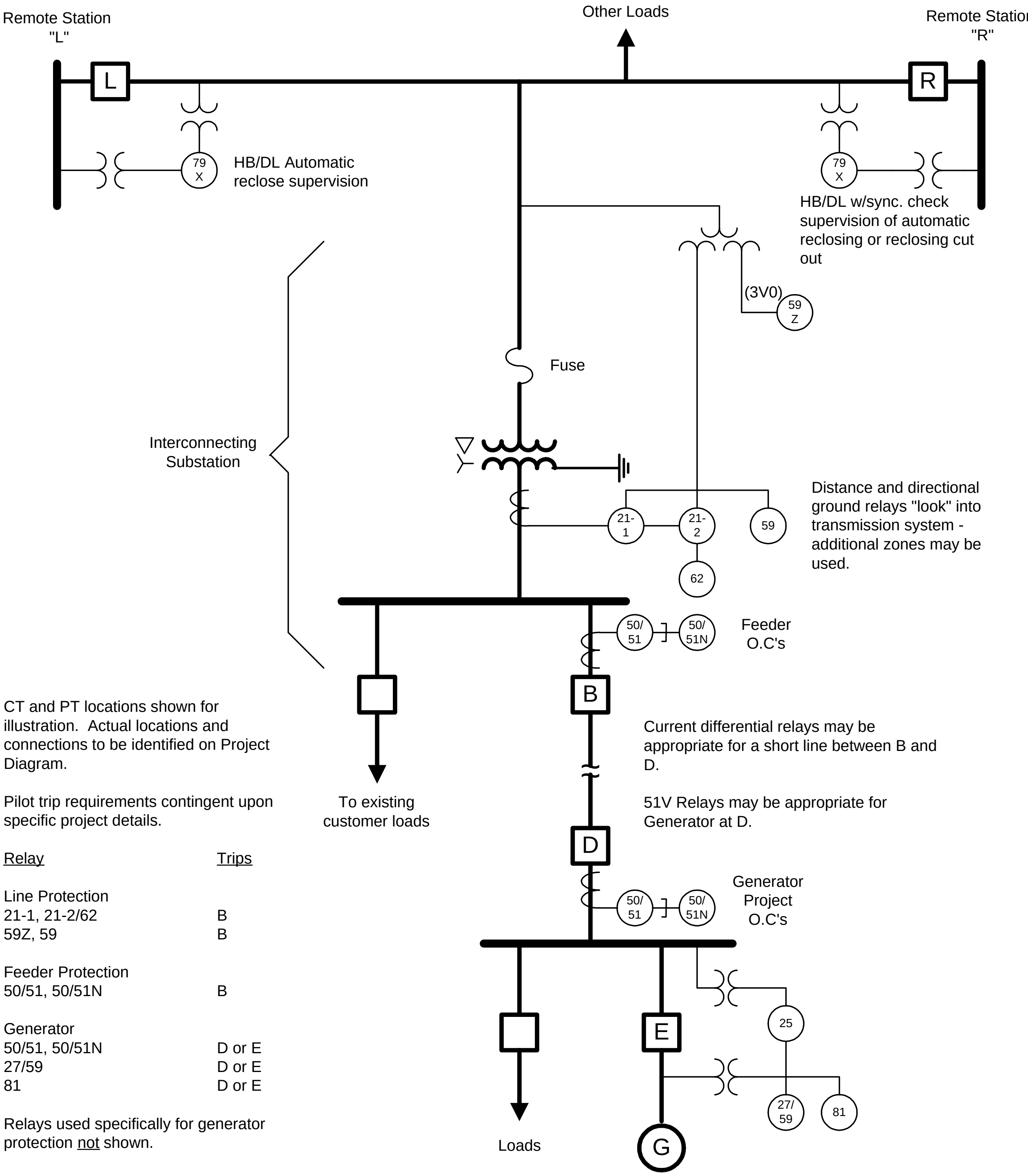


Figure 6-2

Integration of Generation into a Low Voltage Substation Protected by a High Side Circuit Breaker and Connected to a Transmission Line Through a YG-Δ (as shown) or YG-Δ-YG Transformer



CT and PT locations shown for illustration. Actual locations and connections to be identified on Project Diagram.

Pilot trip requirements contingent upon specific project details.

Relay	Trips
Line Protection	
21-1, 21-2/62	B
59Z, 59	B
Feeder Protection	
50/51, 50/51N	B
Generator	
50/51, 50/51N	D or E
27/59	D or E
81	D or E

Relays used specifically for generator protection <u>not</u> shown.

Figure 6-3

Integration of Generation to an Existing Low Voltage Substation Connected to the Transmission line Through a Fused Δ-YG Transformer

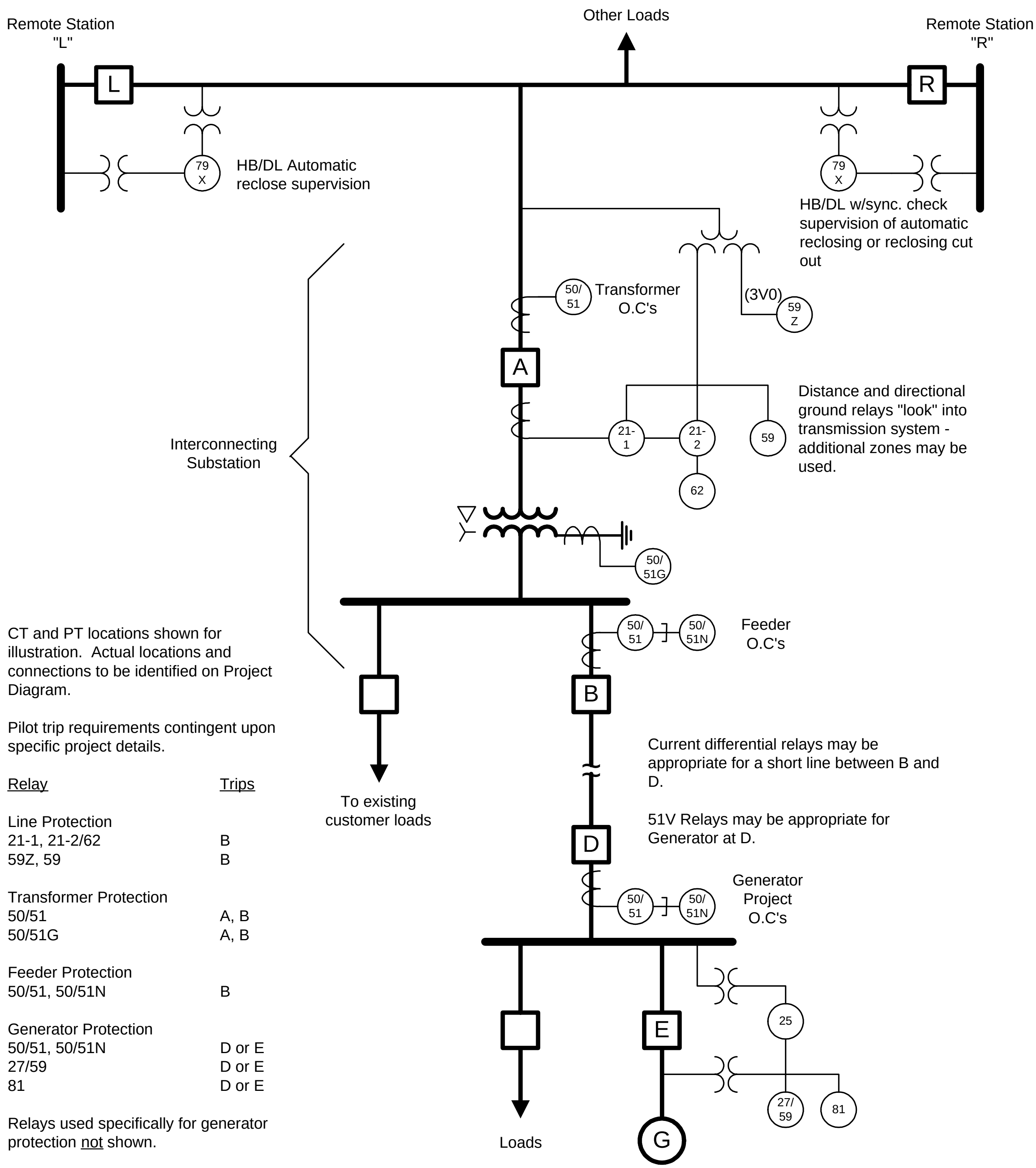


Figure 6-4

Integration of Generation to an Existing Low Voltage Substation Connected to a Transmission line a Δ-YG Transformer and Protected by a High Side Circuit Breaker (Switcher).

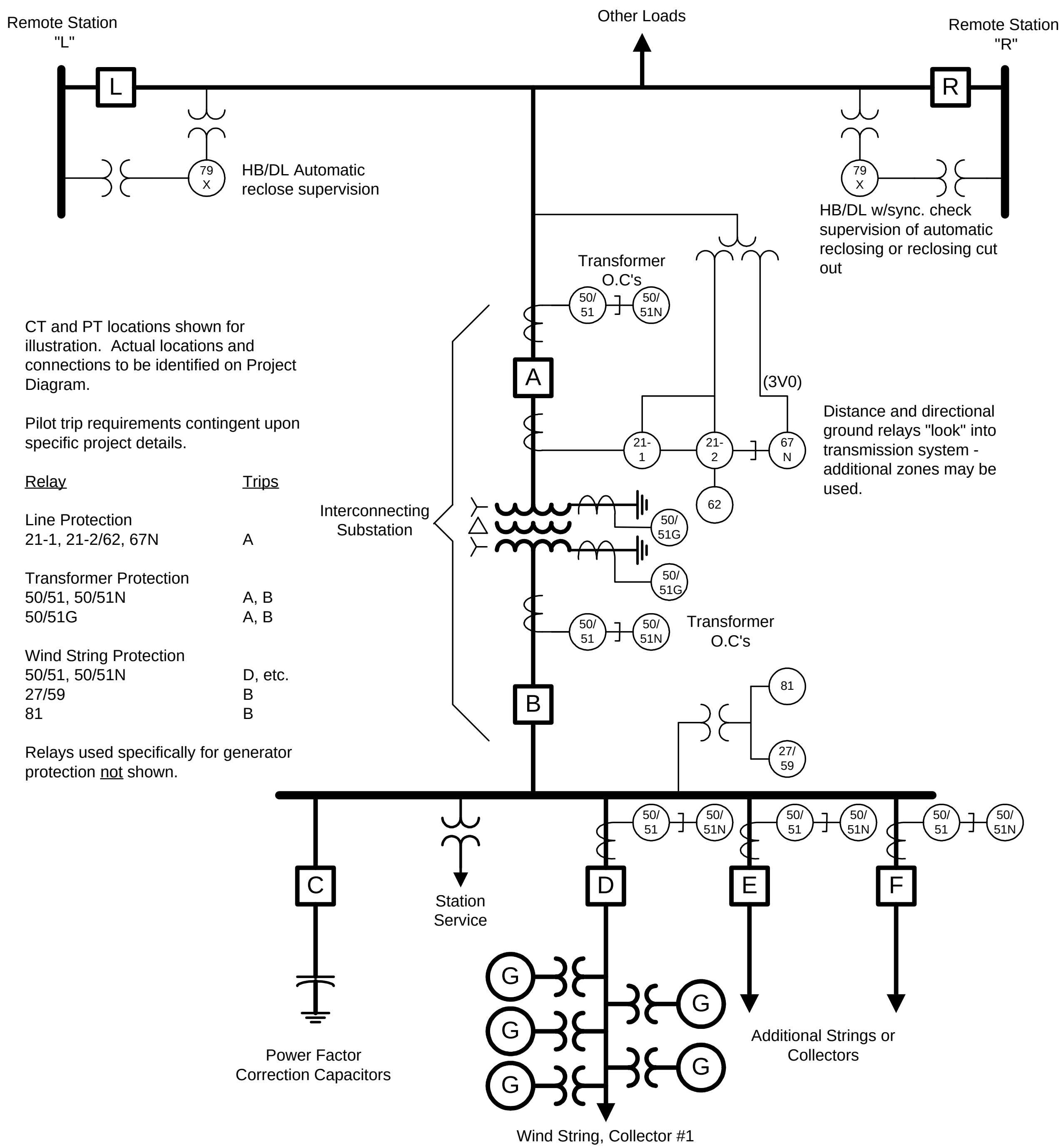


Figure 6-5

Integration of a Typical Wind Farm Induction Generator to a 69 kV or 115 kV Transmission Line Through a YG-Δ-YG Transformer

c. Potential Overvoltages with Delta Connection on the Transmission Side

For ground faults on the high voltage system, protective relaying at the transformer cannot detect zero sequence current at this location unless a ground source (grounding bank) is connected to the high-voltage side of the transformer. Circuit breaker operation(s) at the remote terminal(s) of the transmission line will isolate the line. However, the generator will continue to energize the transmission line creating a 'local island' condition described previously. With one phase grounded, energizing from the transformer low side can result in significant overvoltages (neutral shift) on the unfaulted phases of the transmission line.

It is normally assumed that these overvoltages would equal 1.7 pu. However, studies indicate that the voltages on the unfaulted phases of the transmission line can be even higher than the 1.7 pu, particularly if the generation is large compared to the local load that is islanded with the generator when the line-end breakers trip.

When induction machines are at or near full load, there is usually a considerable amount of capacitance also in service to keep the delivered power factor near 1.0. When the transmission line breakers open, the generator(s) are suddenly unloaded, and there is generally enough capacitance to make the induction machines self-excite. This, in combination with the line capacitance, will cause the voltage to increase above one (pu) at the generator terminals and consequently on the transmission line.

When a synchronous generator is at full load, the excitation system creates a high equivalent internal voltage, supplying the necessary vars to keep the overall delivered power factor near 1.0 and assist with local voltage control. When the system breakers open, unloading the generator, the high internal excitation will increase the voltage on the generator terminals and on the transmission line.

If the generator rating is about the same as the local load on the islanded transmission line, additional overvoltages above 1.7 pu would not be expected. Studies show that if the generator rating is considerably smaller (1/3 or less) than the minimum local load, then the voltage on the islanded system should quickly collapse.

d. Acceptable Solutions to Transmission Line Overvoltages

Overvoltages can potentially damage lightning arresters and other equipment connected to an isolated transmission line. There are three acceptable solutions to resolve the potential overvoltage problems resulting from the Δ-YG transformer neutral shift following a line to ground fault on the transmission line.

1. **High Side Grounding**
   The best and preferred solution to eliminate the 1.7 pu overvoltages is to replace the Δ-YG transformer with a YG-Δ or YG-Δ-YG transformer or install a separate ground source on the transmission line. Wind turbine sites usually require a grounded distribution or collection system, so the YG-Δ-YG transformer configuration is necessary. See Figure 6-5. If the transformer configuration is changed or a separate grounding transformer added, overcurrent protection similar to that described in Section 6-D.1 (a) above can be used.

2. **Transfer Trip**
   Transfer trip is installed from the circuit breaker(s) that clear the transmission line to breakers that can isolate the generator. The breaker that is used for this separation should be as fast as available. One of the line end breakers may even need to be slowed down to insure that it clears last and the islanded generator condition does not occur. Transfer trip is usually necessary when the high side grounding solution is not feasible or for an existing station with a delta connected high side transformer winding. Transfer trip may still be required, even with high side grounding, to meet special protection and/or remedial action requirements.

3. **Broken Delta 3V0 Voltage Detection Scheme**
   It may be possible to use a zero sequence overvoltage (3V0-59) relay connected to the high side of the Δ-YG transformer to detect this ungrounded operation. The 3V0 protection scheme uses three voltage transformers on the primary side of the transformer connected phase-to-ground. The voltage transformers must have a full line-to-line voltage rating and must be capable of measuring voltages up to 1.9 pu voltage continuously. The relay initiates a trip to eliminate the generator infeed on the faulted line. BPA will review each application to determine the acceptability of this scheme. If the 3V0 voltage detection scheme is selected, it may also require the replacement of lightning arresters on the transmission line. The new arresters require a higher rated voltage and higher temporary overvoltage capability properly sized to withstand the expected overvoltage conditions. Other high voltage line to ground equipment that may be damaged by the overvoltage also needs to be replaced.

   The 3V0 open delta scheme cannot protect for the case of overvoltages created when a small generator is isolated in a ‘local island’ with a relatively large amount of capacitance, such as a long line or a capacitor bank. Under and overvoltage relays (27, 59) measuring each phase voltage may be used in conjunction with the 3V0 overvoltage relay to provide additional protection for these conditions.

If a transfer trip scheme or 3V0 scheme is selected to detect a ground on the transmission side of the step-up transformer, it is also critical that the device trip a circuit breaker on the low voltage or grounded side of the step-up transformer. Neutral shift on the high side can limit the interrupting capability of high side devices, possibly causing failure. The number of low side devices allowed to trip for a high side fault may be a consideration. BPA reserves the right to require additional equipment, such as a low side circuit breaker on the transformer, to minimize the number of devices tripped.

6-D.2. Synchronizing and Reclosing

The generator(s) shall be synchronized to the BPA Grid. Circuit breakers under the control of the BPA, required to maintain system integrity, shall not be used for synchronization. All circuit breaker closing operations must automatically synchronize the generator to the transmission system. The BPA Dispatcher must give the generator operator permission before a generator is synchronized to the BPA Grid.

If the generator connects to an existing line, automatic reclosing schemes at the remote terminals will need to be modified to accommodate the generator. A hot bus/dead line check is usually needed at one terminal before attempting an automatic reclose. Hot bus/hot line with synchronism check supervision is necessary for automatic reclosing at the other terminal. For an induction unit(s), automatic reclosing of the breakers at the terminal(s) of the integrating line may be performed without supervision, but will usually be time delayed to assure isolation of the generator(s).

6-D.3. Required Generator Relay Settings

Voltage and frequency relays used for protecting a generator and preventing a 'local island' condition from persisting must meet the requirements listed below to allow proper coordination with the power system. These relays are usually installed at the generation site or at the interconnecting substation.

The ranges, settings, and delays below for both voltage and frequency relays are understood by BPA to be well within the capabilities of small and large modern steam turbines as well as other generators. BPA will evaluate proposed alternative voltage/frequency settings based upon the impact on system performance and reliability. The settings must comply with existing WECC and NWPP requirements.

a. Voltage Relays (27, 59)

The over/under voltage relay setting/delays listed below are intended to insure that generators trip when the connections to the power system have been interrupted, preventing extended 'local islanding.' The 0.8-second minimum undervoltage delay is intended to coordinate with local fault-clearing times to avoid unnecessary generator tripping.

Western Washington and Western Oregon load requirements also insure that generators do not disconnect for dynamic (transient) oscillations on the power system that are stable and damped. The oscillatory frequency of the system during a disturbance ranges between 0.25 and 1.5 Hz. Also, each occurrence of over/undervoltage on the system lasts for a short time period (less than one second) and is nearly damped within 20 seconds following the disturbance. During severe system voltage disturbances it is critical that generators do not trip prior to the completion of all automatic undervoltage load shedding. The settings below coordinate with existing regional undervoltage load shedding plan, where loads are interrupted at voltages ranging from 0.85 pu to 0.92 pu with time delays of 3.5, 5.0 or 8.0 seconds.

Overvoltage (59)

Voltage	Action
1.10 pu	5.0 second minimum delay before unit tripping
1.20 pu	2.0 second minimum delay before unit tripping
1.25 pu	0.8 second minimum delay before unit tripping
1.30 pu and above	no intentional delay before unit tripping

Undervoltage (27)

Voltage	Action
0.90 pu	10 second minimum delay before unit tripping
0.80 pu	2.0 second minimum delay before unit tripping
0.75 pu and below	0.8 second minimum delay before unit tripping

b. Frequency Relays (81)

If a generator facility includes a frequency relay (81) for under and/or overfrequency protection, the frequency settings and time delays must coordinate with the underfrequency load shedding plan. The frequency ranges and minimum setting/delay requirements for over/under frequency relays (81), shown in Table 6-3, have been established by the WECC Coordinated Off-Nominal Frequency Load Shedding and Restoration Program and the NWPP Enhanced Underfrequency Load Shedding Program. The objective of these settings is to use the machine capability to support the power system and prevent unnecessary loss of system load during disturbances, and ultimately, to help prevent system collapse. Generating resources must not trip off before load is shed by underfrequency relays. A generator should not be tripped by frequency relays for frequencies between 59.5 Hz and 60.5 Hz. For frequencies below 56.5 Hz or above 61.7 Hz there are no special requirements for tripping times. However, in the frequency ranges of 56.9 Hz to 59.5 Hz and 60.5 Hz to 61.7 Hz the generator frequency tripping either must not occur, or operate slowly enough to coordinate with load shedding schemes.

Table 6-3 Under and Overfrequency Relay Settings and Operate Times

Underfrequency Range	Overfrequency Range	Minimum Time Delay Setting
60.0 Hz - 59.5 Hz	60.0 Hz - 60.5 Hz	No generator tripping allowed
59.4 Hz - 58.5 Hz	60.6 Hz - 61.5 Hz	3 minutes
58.4 Hz - 57.9 Hz	61.6 Hz - 61.7 Hz	30 seconds
57.8 Hz - 57.4 Hz		7.5 seconds
57.3 Hz - 56.9 Hz		45 cycles
56.8 Hz - 56.5 Hz		7.2 cycles
Less than 56.4 Hz	Greater than 61.7 Hz	Instantaneous trip

For generators that are not susceptible to damage for the frequency ranges listed above (e.g. typical hydro units), tripping at 61.7 Hz and 56.4 Hz, with no intermediate steps is suggested. For steam generators and similar units, relay(s) with multiple frequency setpoints and discrete time delays could be used to realize the settings above.

Often, large generation resources are directly connected to a substation at the transmission level voltage and would not be part of the ‘local island’ condition previously described in Section 5-F. For these generators, the 61.7 Hz trip level may be raised and the 56.4 Hz trip level may be lowered. However, the minimum delays listed above for all frequency deviations from 60 Hz must be maintained. For those generators that can be part of a 'local island', a maximum delay of 0.1 sec at 56.4 Hz and 61.7 Hz should be used. This will help insure that the generator trips for the ‘local islanding’ condition.

Voltage and frequency relays must have a dropout time no greater than two cycles. Frequency relays shall be solid state or microprocessor technology; electro-mechanical relays used for this function are unacceptable.

6-D.4 Generator Relays

Except as specifically identified in these technical requirements, BPA does not have requirements for the type of protection used for a generator. Generator protection is the responsibility of the Requester. However, the protection should meet the general requirements of the *NERC/WECC Planning Standards*. The level of redundancy and overlap of protection schemes are determined by the Requester. BPA's primary concern with generator protection is that the protection is available to isolate a generator fault from the BPA Grid. Types of protection used to isolate a generator from the BPA Grid include:

a.	Percentage differential	(87)
b.	Phase balance current	(46)
c.	Phase sequence voltage	(47)
d.	Reverse power	(32)
e.	Thermal	(49)
f.	Loss of field	(40)
g.	Over-speed device	(12)
h.	Transformer sudden pressure	(63)
i.	Voltage controlled/restrained o.c.	(51-V)
j.	Volts per Hertz (overexcitation)	(24)
k.	Neutral overvoltage	(59-N)
l.	Under-, overvoltage relays	(27, 59)*
m.	Under-, overfrequency relays	(81)*

*The settings of 27, 59 and 81 relays must be reviewed and approved by BPA.

6-E. Special Protection or Remedial Action Schemes

Connections to the BPA Grid may require special protection or remedial action schemes, (RAS). The need for RAS will be determined during the interconnection studies. The type of RAS depends upon several factors such as type of connection, location of connection, etc. Some RAS must be fully compliant with WECC requirements. WECC RAS criteria specifies no single point of failure which, in most cases, includes geographically diverse communication paths. WECC compliant RAS schemes must also be tested annually by BPA personnel. The annual test includes an operational or functional test of the scheme. The most common special protection schemes include load shedding, line loss detection, and generator tripping.

BPA staff will design most RAS schemes, but if any part of the scheme is designed by the Requester or their designate, that design must be reviewed and approved by BPA. BPA will ensure the design meets BPA and WECC requirements. If the Requester designs a portion of the scheme, they must be prepared to present the design to the WECC Remedial Action Scheme Subcommittee for acceptance. If the WECC Remedial Action Scheme Subcommittee determines changes must be made, the changes will be the responsibility of the Requester.

The Requester is expected to provide sufficient rack space in their facilities to accommodate additional equipment for relaying, telecommunications, special protection or RAS Schemes needed to facilitate the interconnection.

6-E.1 Load Shedding

The proposed connection may require special load shedding schemes based upon BPA Control Area requirements. These may include underfrequency load shedding, undervoltage load shedding, or direct load tripping. The intent of load shedding is to balance the load to the available generation resources, reduce the possibility of voltage collapse, and to minimize the impact of a system disturbance. Underfrequency load shedding generally includes a coordinated restoration plan, which is intended to minimize frequency overshoot following a load shedding condition. Tripping levels, restoration, and other details of load shedding schemes will be determined by BPA, following NERC, WECC and NWPP criteria. Section 6-D3 includes specific requirements for generation tripping by voltage and frequency relays.

a. Direct Load Tripping

Direct load tripping may be required for large loads, typically in excess of 50 megawatts. Direct load tripping is achieved with the use of redundant, dedicated transfer trip schemes from the remedial action scheme controllers to the load. Communications channels may be either digital or analog. Communication channels should be alternately routed. BPA Dispatchers will enable or disable direct load tripping schemes depending upon system conditions.

b. Underfrequency Load Tripping

Underfrequency load tripping may be required to balance generation resources and loads. Underfrequency load shedding must meet the following requirements:

1. Electromechanical frequency relays (81) are not allowed.
2. Frequency relays should be of the definite time variety.
3. Total operate time for underfrequency load tripping, including circuit breaker tripping, shall not exceed 14 cycles.
4. The frequency relay should be voltage supervised to prevent operation when the bus voltage drops below 0.7 pu voltage.
5. The frequency element (81) may be included as a part of a multifunction protective relay.
6. Frequency setting levels will be supplied by BPA.
7. Load restoration settings will be supplied by BPA.

c. Undervoltage Load Tripping

Undervoltage load tripping may be required to prevent possible voltage collapse on loss of major transmission paths or generation resources. Undervoltage load shedding must meet the following requirements:

1. Electromechanical voltage relays (27) are not allowed.
2. Voltage relays should be of the definite time variety.

3. The voltage transformer source for the voltage relay (27) must be on the source side of any automatic load tap changers or voltage regulators.

4. A three-phase voltage element must be used to detect the undervoltage condition. Averaging of the three phase voltages is not acceptable.

5. The undervoltage element (27) may be included as a part of a multifunction protective relay.

6. The undervoltage relay should not operate for a single-phase low voltage nor for a three phase low voltage below 0.5 pu.

7. Total operate time for undervoltage load tripping shall be greater than expected fault clearing times, typically 30 cycles or 0.5 seconds.

8. Voltage setting levels and operate time delays will be supplied by BPA. Typical settings may be 0.9 to 0.92 pu voltage with a delay of 3.5 to 8 seconds.

9. Restoration settings will be determined by BPA.

6-E.2. Transmission Line Loss

New transmission lines may require line loss detection logic, (LLL). Line loss is typically sensed by the position of the circuit breaker (52/b) auxiliary switch, isolating disconnect switch status, and also from the circuit breaker trip bus. Substation bus configuration and the type of protective line relaying will determine the exact requirements for implementing line loss detection logic. Line loss sensing must be implemented at all terminals of the transmission line. Line loss detection is sent to the appropriate BPA RAS controllers via redundant transfer trip channels.

6-E.3. Generation Reduction

New generation will most likely require the addition of a generator dropping and perhaps a generator run back scheme. These schemes are intended to maintain the balance between system loads and available generation during and following a system disturbance. They may also be used to prevent transmission system overloads during abnormal operating conditions. BPA Dispatchers will arm or disarm generator tripping and run back depending upon system conditions. These schemes must be fully redundant. BPA RAS controllers will send generator reduction signals to the generators via redundant transfer trip channels. If the new connection includes generation not previously part of the BPA Control Area, the generation may also require additional special trip schemes and RAS arming procedures. These schemes will typically require a sequential events recorder as described in Section 6-G.

It is the plant operator's responsibility to develop and maintain procedures for the arming of the generator units for the RAS and also procedures for plant restoration following a RAS action.

a. Generator Dropping
Generator dropping or tripping is the most commonly applied RAS. Generator dropping is achieved with the use of redundant, dedicated transfer trips from the BPA RAS controllers to the power plant unit breaker trip circuits.

b. Generator Run Back or Ramp Down
Generator run back may be used in addition to generator tripping. Runback will allow the generation output levels to be decreased to a pre-agreed upon level within a pre-agreed upon time. A stand alone run back or ramp down scheme is rarely allowed. If the runback scheme must be WECC compliant, it will be backed up by a WECC compliant generation dropping scheme.

6-E.4 Other Special Protection and Control Schemes

The location of the POI, amount of load or generation expected and various other system conditions may require special protection schemes. The need for and type of schemes required will be determined as part of the system studies done following the request for a new connection. For example, RAS may be required for stability purposes or out-of-step tripping may be needed for controlled system grid separations. Generator or load tripping may be required to prevent line or equipment overloading. Special breaker tripping or closing schemes such as staggered closing or point-on-wave closing may be necessary to reduce switching transients. These special protection and control schemes may require stand-alone relay systems or additional capabilities of particular substation equipment.

6-E.5 Telecommunications Requirements for Special Protection or Remedial Action Schemes

Many of the special protection schemes described in this section will require telecommunications channels for transfer trip between the RAS controllers and the remote device. If the RAS is part of a scheme that must comply with WECC criteria, it will require redundant transfer trips, redundant channels, and in most cases, geographically diverse communication paths. Specific details for telecommunications channels are in Section 8, *Telecommunications Requirements.*

6-E.6 RAS Design and Operational Requirements

Minimum requirements for a RAS scheme include the following:

- The RAS should be independent of all other control actions.
- The RAS will have a common architecture as much as possible with existing schemes.
- The RAS will utilize standard alarms to identify operation actions and trouble.
- The RAS scheme must be designed with the ability to safely test the

scheme.

- The RAS will be provided with the ability to arm/disarm via SCADA if a SCADA RTU is available.

6-E.7 Future Modifications or Revisions to Special Protection or Remedial Action Schemes

Any modification, change, or revision of an installed RAS scheme at a requestor's site must be reviewed by BPA before it is implemented. Proposed changes may also have to be reviewed by the WECC Remedial Action Scheme Subcommittee.

6-F. Installation and Commissioning Test Requirements for Protection Systems

Thorough commissioning or installation testing of the protection system(s) is an important step for the installation of a new terminal or when changes to the protection system are made. The protection system includes the protective relays, the circuit breakers, instrument transformer inputs, and all other inputs and outputs associated with the protection scheme. The actual protection equipment used will determine the type and extent of commissioning tests required. Following are the minimum tests that must be performed on protection schemes at the POI that could affect the BPA Grid.

6-F.1 Verify All Protective System Inputs

a. Check for proper ratio, polarity, connections, accuracy, and appropriate grounding on current and voltage transformer circuits.
b. Verify that shorting of unused current transformer windings is proper and that windings used for protection systems are not shorted.
c. Verify that all other inputs to the protection system including battery supplies, circuit breaker auxiliary switches, pilot channel inputs, etc. are correct.

6-F.2 Verify Protection System Settings

a. Check protection system settings and programming.
b. Perform acceptance or calibration tests of the protection system if it was not performed previously.
c. Verify that any changes in relay settings required for relay acceptance testing are restored to the desired settings.

6-F.3 Protection System Drawings and Wiring

a. Verify switchboard panel wiring is intact and matches drawings.
b. Verify interconnections between protection system and other devices are intact and match drawings.
c. Verify that the drawings are correct.

6-F.4 Verify All Protective System Outputs

a. Verify that all trip outputs will trip intended trip coil(s).
b. Verify that all close outputs will properly close the breaker(s).

c. Verify proper relays key the appropriate pilot channel.

d. Verify other outputs such as breaker failure initiate, special protection scheme signals, reclose initiate and reclose block, relay alarms, event recorder points, and any other relay outputs to other equipment.

6-F.5 Perform Trip or Other Operational Tests

a. Assure correct operation of the overall protection systems.

b. Test automatic reclosing.

6-F.6 Pilot Schemes

a. Measure channel delays.

b. Check for noise immunity.

c. Check for proper settings, programming, etc.

d. Check transmit and receive levels.

e. If automatic channel switching or routing is utilized, check for proper relay operation for alternate routing.

6-F.7 In Service, Load and Directional Tests

a. Measure AC current and/or voltage magnitudes applied to the relay system.

b. Measure AC current and/or voltage phase angles applied to the relay system.

c. Test the relay system for proper directional operation when applicable.

6-F.8 Special Protection Scheme/Remedial Action Scheme Testing

a. The RAS must be thoroughly tested prior to energization. This includes an end-to-end test, functional test, or operational tests.

b. If the RAS is a part of a WECC compliant RAS, an annual functional or operational test is required.

Many utilities now use coordinated end-to-end tests to verify the overall operation of the protection system and the pilot channel as part of their commissioning tests. This method is acceptable to BPA.

Modifications to a protection system or RAS scheme also requires testing similar to that listed above. The extent of testing and types of tests required depend upon the changes made. Modifications include changes or additions to protection circuits, changes or upgrades of protective relay firmware, and changes in protective relay logic and/or programming. Many utilities also consider it good practice to perform various levels of tests and calibrations following changes in protective relay settings. When making protection system modifications, attention must be paid to any circuits that may be inadvertently affected (e.g.) an auxiliary relay having multiple circuits tied to its outputs.

6-G. Disturbance Monitoring

Depending upon the type of connection, location, and operating voltage, disturbance monitoring equipment may be required. The monitoring equipment is intended to record system disturbances, identify possible protection scheme problems, and to provide power quality measurements. Sequential event recorders, digital fault recorders, (DFR) and dynamic disturbance recorders may be required. BPA may require remote access to these recorders and relay systems at the POI. Upon request, and if available, BPA will reciprocate by supplying the Requester with limited access to the corresponding equipment at the remote BPA terminals.

6-G.1. Sequential Event Recorders (SER)

These devices time tag digital events occurring in a substation. They must have a one millisecond time resolution when recording events. The SER uses a Global Positioning Satellite (GPS) clock receiver for a timing reference. The SER should have sufficient channels to monitor relay and RAS performance, circuit breaker positions, generator status, and other events within the interconnecting substation or generator plant. SERs are required in all 500 kV substations. Generators that are part of a WECC compliant RAS must also have SERs. The SER must have capability for remote communications to connect to BPA's SER master station. At lower voltage substations, the event recording capability of multifunction digital relays may be a possible substitute for a dedicated SER.

6-G.2 Digital Fault Recorders (DFR)

The DFR must have sufficient analog channels to monitor critical currents and voltages. The DFR may also include digital channels to monitor selected equipment status in the substation. The DFR must be time synchronized via a GPS satellite clock. For 500 kV substations, a stand-alone DFR is required. For lower voltages, it may be acceptable to use multifunction digital relays that have oscillography capability. Such a relay must be synchronized to a GPS clock. Both the DFR and digital relays that provide protection for the BPA Grid must have remote communications capability such that BPA personnel can retrieve information.

6-G.3 Dynamic Disturbance Recorders

A dynamic disturbance recorder may be required at key 230 kV and higher voltage substations, major load centers, and generating stations with a combined 1500 MW or greater output at the same POI. Precise details and locations are determined by the WECC Disturbance Monitoring Work Group. The disturbance recorder should record bus voltage and frequency, line currents, MW and Mvar. Measurement of additional status and control information may be required. The recorder must be able to either record data locally with a ten day minimum continuous archive or be connected to the master station at the BPA control center for real-time data transmission and recording. Phasor measurements are preferred, but other measurement types may be acceptable. Data must be time stamped to at least one millisecond accuracy, though phasor measurements should be at a five-microsecond accuracy in accordance with the IEEE standard (PC37.118). Additional status and control system measurements may be required for WECC compliance.

7. Data Requirements for System Operation and Scheduling

7-A. Introduction

All transmission arrangements for power schedules within, across, into or out of the BPA Control Area require metering and telemetering. Some generators or loads that are in another control area, referred to as 'host' control area, may also require metering and telemetering to the BPA Control Area. Transmission arrangements with loads, generators, or new transmission facilities may include voltage control, and automatic generation control (AGC). The WECC Reliability Coordinator for the region needs data to ensure the reliable operation of the entire grid. The technical plan of service for interconnecting a load, generator, or new transmission facility is shown on the project requirements diagram (PRD) and includes the metering and telemetering equipment consistent with the transmission contract, or control area services agreement. Such metering and telemetering equipment may be owned, operated, and maintained by BPA or by other parties approved by BPA. Telecommunications requirements for data collection are included in Section 8.

Revenue billing, system dispatching, operation, control, transmission scheduling and power scheduling each have slightly different needs and requirements concerning metering, telemetering, data acquisition, and control. Specific requirements also vary depending upon whether the new connection is physically connected to the BPA Grid or electronically connected via telemetering placing the Project with the BPA Control Area.

7-B. Telemetering Control Center Requirements

BPA requires telemetering data for the integration of new interconnections at adjacent control area boundaries, as well as new generation within the BPA Control Area. This typically consists of the continuous telemetering of active power quantities (in kW) and hourly transmission of the previous hour's energy (in kWh) from the Point Of Interconnection, (POI) to the appropriate BPA Control Center. Table 7-1 summarizes the general metering and telemetering requirements and Table 7-2 identifies requirements based on connection location. The following are general requirements for telemetering:

7-B.1 Facilities Tied to the BPA Control Area Boundary

Telemetering is required for all normally closed interconnections at a BPA Control Area boundary. For this case, telemetering of active power and energy (kW, kWh) is required. There may also be a need for reactive power (kvar, kvarh) information for purposes of billing based on power factor. High capacity interconnections may require redundant metering and telemetering.

For connections that are to be normally open, or closed only for emergencies, BPA determines telemetering needs on a case-by-case basis.

Table 7-1 General Metering and Telemetering Data Requirements

System or Quantity	BPA Dispatching and Operations	Transmission Scheduling	Revenue Billing
kW	Yes	No	No[1]
kWh	Yes	Yes	Yes
Kvar	Case-by-case	No	No
Kvarh	Case-by-case	No	Yes
kV	Yes	No	No
Load Size	≥ 1 MVA	≥ 1 MVA	≥ 1 kW
Data Sample Rate	kW: 1 second or other approved rate compatible with NERC policy	Last hour kWh sent each hour	Hourly kWh data retrieved daily (RMS[2] type system)
Tie Capacity	All normally closed ties	All normally closed ties	All ties
AGC	Yes[3]	Yes[3]	No
Generation Reserves	Operating, spinning, regulating, & MW capability	Actuals as delivered	Actuals as delivered

Notes:
1. A kW reading for revenue billing may be required where special transmission arrangements are necessary.
2. Dial-up phone line required for the RMS.
3. All control area boundaries & customer connections providing ancillary services.

Table 7-2 Metering, Telemetering and SCADA Data Requirements vs. Connection Location

Connection to BPA Grid	Connection Located Inside BPA Control Area	Connection Located Outside BPA Control Area
Direct Electrical Connection[1]	kW, kWh, RMS[2], kvar, kvarh, kV circuit breaker status & control	kW, kWh, RMS[2], kvar, kvarh, kV circuit breaker status & control
No Direct Electrical Connection [1]	kW, kWh, RMS[2]	kW[3]

Notes:
1. Dedicated circuit is required for kW, kWh, kvar, kvarh, and kV.
2. Dial-up phone line required for RMS.
3. kW is required if capacity of WECC path BPA manages is impacted.

Table 7-3 Metering, Telemetering and SCADA Data Requirements for Loads, (L), Including Station Service, At the Meter Point and inside BPA Control Area

Quantity	L < 1 MVA	*1 ≤ L < 25 MVA*	*L ≥25 MVA*
Billing Information [RMS[3]]; Hourly kWh & kvarh[2]	Yes If L ≥1 kW	Yes	Yes
Hourly Estimate of Load (by web, FAX, or phone)	No	Yes[4]	Yes[4]
kW Continuous Data	No	Yes	Yes
Loss of Meter Potential Alarm	No	Yes	Yes
Telemetering Equipment Failure Alarm	No	Yes	Yes
Uni-Directional kW & Bi-Directional kvar Meter	Yes	Yes	No
kV	No	Yes If L ≥ 10 MVA	Yes
Kvar	No	Yes If L ≥ 10 MVA	Yes
Redundant Meters	No	No	Yes

Notes:
1. Hourly estimate of load must equal the sum of transmission schedules for delivered power.
2. Hourly integration of kvar may be used for reactive billing if kvarh not available from meters.
3. RMS requires dial-up phone line.
4. Required from the scheduling agent to BPA.

Table 7-4 Metering, Telemetering and SCADA Data Requirements for Generation

System or Quantity	G < 3 MVA	$3 \leq G < 50$ MVA Local[2] Load Only	$3 \leq G < 50$ MVA Exporting Output	$G \geq 50$ MVA
Billing information (RMS)	Yes, if $X \geq 1$ kW No, if $X < 1$ kW)	Yes	Yes	Yes
Hourly Estimate of Generation [1] (by web, FAX, or phone)	Conditional[2]	Yes	Yes	Yes
Hourly kWh (telemetered)	No	Yes	Yes	Yes
kW Continuous Data	Yes If $G \geq 1$ MVA	Yes	Yes	Yes
Loss Of Meter Potential	No	Yes	Yes	Yes
MW & Mvar on Each Unit [3]	No	No	No	Yes If integrated at 230 kV or above
Uni-directional kW & Bi-directional kvar meter	Yes	Yes	No	No
Bi-directional kW & kvar Meter	No	No	Yes	Yes
Redundant Meters	No	Yes If $G \geq 25$ MVA	Yes If $G \geq 25$ MVA	Yes
Gen-ICCP (Redundant Links)	No	No	No	Yes [4]

Notes:

1. Hourly estimate of generation must equal the sum of transmission schedules for marketed power. It is required from the scheduling agent to BPA
2. Hourly estimate is not required if generation is serving local load only. It is required if generation is being used as a marketing resource. Local load is defined as load that is on the generator side of the meter.
3. Separate meters for each unit are required when generators per line are not identical.
4. Possible exception for intermittent projects such as wind generators.
5. Required if BPA is the designated scheduling agent.

7-B.2 Loads Within BPA Control Area

For loads with direct electrical connections to the BPA Control Area, AGC telemetering is not normally required. For interruptible loads, BPA determines telemetering needs on a case-by-case basis. Connecting eccentric

(non-conforming) loads may require an interface to the BPA AGC system. Existing practices throughout North America usually require a warning signal of pre-loading in order to assure that adequate generation reserves are spinning before any sudden load change occurs. Table 7-3 summarizes metering, telemetering, and SCADA requirements for loads based upon size.

7-B.3 Generation Within BPA Control Area

For generation connected internally to the BPA Control Area, telemetering is required for generation facilities of aggregate output equaling or exceeding three MVA. For this case, telemetering of real power and energy (kW, kWh), and reactive power (kvar, kvarh) is normally required. BPA will determine telemetering needs on a case-by-case basis for generation sites that remain below three MVA. Station service load may require separate telemetering if it comes from a different control area. Station service taken directly from the generator POI may require separate metering and separate current transformers to accurately measure the station service load. Table 7-4 summarizes metering, telemetering and SCADA requirements for generation within the BPA Control Area.

Metering and telemetering for temporary generation installations (planned for less than one year of service) will be determined on a case-by-case basis.

Generation sites with an aggregate output equaling or exceeding 50 MVA may require a direct link with BPA via a generation ICCP communication server in order to send and receive data directly from the BPA AGC System. ICCP is the Inter-Control Center Communications Protocol, defined by IEC 870-6 TASE.2 standard. See Section 7-C.2 for additional details on the ICCP requirements. Wind projects and other intermittent generation may be exempted from these criteria, subject to a case-by-case review.

WECC requires any generation plant over 200 MVA to have data sent to the Extra High Voltage (EHV) Data Pool. BPA will provide the required data to the EHV Data Pool for any plant over 200 MVA in the BPA Control Area unless the generator is a WECC member. In that case, the generator is responsible for reporting to the EHV Data Pool directly or via an agent.

7-B.4 Jointly-owned Load or Generation

Telemetering for interconnection of shared or jointly owned loads or generation commonly use dynamic signals. These signals are usually a calculated portion of an actual metered value. The calculation may include adjustments for losses, changing ratios of customer obligations or shares, or thresholds and limits. Two-way dynamic signals are used when a customer request for MW change that can only be met by an actual change in generation. In this case, a return signal is the official response to the request and its integrated value is designated the official meter reading. Previous integration intervals were typically one hour. Some types of dynamic signals may require shorter integration intervals. The integration interval is determined by the type of service provided consistent with BPA tariffs to properly account for transmission usage. BPA uses the NERC recommended 'accumulator method' for accounting, not the 'rounding method' for integrated values.

7-B.5 Generation in the BPA Control Area Not Controlled by BPA

Telemetering is required for generation located internal to the BPA Control Area to account for the scheduling that is required to deliver that energy to the appropriate host control area. The requirements are similar to interchange telemetering requirements. In this case, Gen ICCP is typically not required by BPA.

7-C. Data Requirements for Control Area Services

The following are the data requirements for control area services if the requestor wishes to locate a load or generator in the BPA Control Area

7-C.1 Requirements for Interconnected Loads

Non-traditional sources are sometimes used for supplying ancillary services. If a load provides regulating or contingency reserve services, data requirements for deployment of the reserves will be similar to those applied to generating resources. To the extent that a third party may externally supply regulating or contingency reserve services at the BPA Control Area interconnecting boundary, data requirements for their deployment may be similar to those applied to generating resources.

Technical discussions are necessary before the specific data requirements can be determined. The following provides a brief overview of these requirements:

a. Supplemental AGC Services

If BPA is purchasing supplemental AGC services, AGC interface is required on a long-term basis. Prior to BPA purchasing supplemental services, an investigation into the capabilities, cost, and benefits of AGC control is required to determine the specific AGC requirements. Most supplemental services are scheduled and delivered using real-time dynamic signals, thus requiring telemetering.

b. Ancillary Services

Ancillary Services requirements are also driven by how the interconnected customer chooses to meet these obligations. Either the Requester or the entity making the transmission arrangements is responsible for meeting obligations for necessary ancillary services associated with the interconnection. Most self-provided ancillary services are scheduled and delivered using real-time dynamic signals, which require telemetering. The responsible party may fulfill these obligations in any of the following ways:

- Directly provide ancillary services by making resources available to BPA to deploy
- Contract with a third party to make resources available to BPA to deploy
- Contract with BPA to cover this ancillary services obligation

The Requester must demonstrate that the selected options are technically sound and meet all relevant reliability policies and criteria of NERC, WECC and NWPP or their successors as well as the BPA business practices.

Where a third party is providing ancillary services, the following data is required with a sampling rate established in BPA's business practices – typically four seconds between samples for regulation and ten seconds for operating reserves:

- Net instantaneous active power transferred (in MW)
- Instantaneous reactive power (in Mvar) and total reactive power (Mvarh) transferred
- Operating reserve capability during the upcoming ten minutes
- kWh for most-recent hour
- Area Control Error (Station Control Error for Generating unit)
- Actual Scheduled Interchange

c. Supervisory Control and Data Acquisition System (SCADA)

Additional data may be required from loads such as steel rolling mills and wind tunnels, in order to make generation control performance more predictable. Such additional data may include, but not be limited to, precursor signals of expected load changes. SCADA control may also be required. Specific requirements and needs are determined for each load. This may require a separate SCADA remote terminal unit or it may require data be added into an existing SCADA as determined by BPA.

7-C.2 Requirements for Interconnected Generation

Data requirements for control area services, such as regulation or operating reserves, apply only to generation resources inside the BPA Control Area. For resources that are not part of BPA's Control Area, the operator of the Host control area determines the data requirements.

Inter-Control Center Communication Protocol (ICCP) is a standard communications protocol for data exchange used by BPA and many other entities. ICCP is an international standard for communications of real time data. The IEC 870-6 TASE.2 Standard defines the ICCP. The ICCP protocol is being revised to include certificate authentication and encryption for security purposes. When this package is available, all ICCP servers must be retrofitted. BPA has two systems that communicate via ICCP. The first is GEN ICCP used for exchanging generation data between the BPA Control Center and the Generation facility. It is an internal, point-to-point service. The second system, called simply ICCP, was previously known as inter-utility data exchange. It is used to exchange SCADA data between BPA and other utilities and control area operators. This form of data exchange uses public switched telecommunications services.

For generation resources inside the BPA Control Area, Ancillary Services, (e.g. reserves) must be acquired. Provision for all Ancillary Services are specified in the transmission or control area services contract. BPA must specifically approve all arrangements for generators intending to provide Ancillary Services to BPA. If the generator is capable of providing Ancillary Services in excess of its obligation, then BPA may choose to contract with the generator operator to provide additional Ancillary Services.

Technical discussions between BPA and generator developers are necessary before the specific implementation requirements can be determined. For generation facilities with a total capacity of 50 MVA or above, Gen ICCP will generally be required to bring in unit information as well as MW, Mvar and kV from the project. The AGC data to be passed over the data link may include some or all of the data quantities listed in Table 7-5. For each project a detailed data requirements list with definitions will be provided during the design phase of the interconnection of the project. Actual generator specific data requirements are developed after an Interconnection Agreement or Control Area Services Agreement is signed.

Wind projects may be exempt from the ICCP requirement, but will be required to provide kW, kvar, kV and interconnection circuit breakers(s) status, at a minimum. All wind projects with external capacitor compensation will be required to have automatic control on a voltage schedule provided by BPA Dispatchers. Status and availability of each external capacitor may also be required. Projects with internal automatic var compensation (i.e. double fed wound rotor) may be required to receive a voltage set point signal. This will be determined on a case-by case basis.

a. Automatic Generator Control Services

If BPA is purchasing ancillary services from the generation facility, AGC control of the generator capability is required on a long-term basis. Prior to purchasing AGC services, a capabilities, cost, and benefit investigation as to the AGC control capabilities of the generation facility is required to determine the specific AGC requirements.

b. Ancillary Services

Requirements for Ancillary Services are also driven by how the generator operator or the purchaser chooses to meet the reserve obligations of the generation facility, as described below. Either the generation operator or the entity making the transmission arrangements is liable for the reserve obligations associated with the operation of the generation facility consistent with the BPA Tariff. Generation marketed as interruptible power is treated separately under special provisions and guidelines by the WECC and BPA. The responsible party may fulfill these obligations in any of the following ways:

- Make these reserves available to BPA from the generating facility
- Make these reserves available to BPA from another one of their generation resources
- Contract with another generator operator to make these reserves available to BPA on their behalf
- Contract with BPA to cover this reserve obligation

c. Supervisory Control and Data Acquisition (SCADA) Requirements

New substations may require BPA SCADA control and status indication of the power circuit breakers and associated isolating switches used to connect with BPA. SCADA indication of real and reactive power flows and voltage levels are also required. If the connection is made directly to another utility's transmission system, SCADA control and status indication requirements shall be jointly determined with the Requester, and BPA. SCADA control of breakers and isolating switches that are located at other than the generating facility are not normally required, although status and indication may be necessary for system security purposes. Section 8-D discusses telecommunications requirements for SCADA systems.

d. GEN ICCP Installation

A GEN ICCP installation may be required for generation facilities greater than 50 MVA and is required for generation facilities over 200 MVA. If BPA is not providing any ancillary services, a GEN ICCP configuration with single server and single router are acceptable. If BPA is providing ancillary services, a primary server and back up server must be installed. If BPA is doing automatic generation control, redundant servers and redundant routers are required. The GEN ICCP installation at the generating facility provides capability to bring additional data from the generator(s) to the BPA control centers. Table 7-5 shows the typical GEN ICCP data required.

Table 7-5a Automatic Generation Control (AGC) Quantities

Generation Plant to BPA Control Center(s):	
1.	Plant in BPA AGC mode / local mode [1]
2.	Net instantaneous power output (MW), unit MW output for plants >200 MW
3.	Plant output attributed to natural governor response (MW)
4.	Plant ramp rate capability – maximum raise and lower
5.	Plant jerk rate capability (rate of change of ramp rate) – maximum raise and lower
6.	Regulating reserve capability - during next 10-minutes
7.	Spinning reserve capability - during next 10-minutes
8.	Operating reserve capability - during next 10-minutes
9.	Maximum capability - normal conditions
10.	Maximum capability - power system emergency conditions
11.	Minimum generation capability
12.	Unit power system stabilizer and automatic voltage regulation status
13.	Unit status - defined below for each generator unit in numerical order.
	— Out of Service - unit not available for use on 10 minutes notice.
	— Standby Mode - unit available for use on 10 minutes notice.
	— Standby Mode - unit available for use within 60 minutes
	— On-line / Not on AGC
	— On-line / On AGC
	— On-line / Condensing
14.	Total Mvar output, unit Mvar output for plants >200 MW
15.	Total instantaneous maximum Mvar capacity boost or each POI voltage level
16.	Total maximum Mvar capacity boost or each POI voltage level
17.	Total instantaneous maximum Mvar capacity buck or each POI voltage level
18.	Total maximum Mvar capacity buck
19.	Plant in BPA kV mode / local kV mode [2]

Table 7-5b Automatic Generation Control (AGC) Quantities

BPA Control Center(s) to Generation Plant:	
1.	Generation request at rated frequency set point - AGC-requested power output level in MW for the following look-ahead time horizons: 0, 5, 10, 15, 20, and 30 minutes.
2.	Generation requested rate of response.
3.	Amount of regulating reserve to carry.
4.	Generation base point - The generation level in MW at which BPA expects to be operating the plant at the end of the ramp.
5.	Plant MW control mode - regulating, base load, standby, or off control
6.	BPA operating mode indication to the plant – normal, assist, emergency
7.	Bus voltage schedule(s) in kV and actual measurement(s)
8.	BPA AGC control center identifier - Dittmer or Munroe Control Center
9.	BPA Mvar Control Mode – coordinated voltage schedule, nominal voltage schedule

Notes:

1. When plant is in BPA AGC mode, the BPA AGC system is enabled at the plant. The plant is controlling power output to meet the generation request and generation rate of response (MW/minute) originating from BPA. When the plant is in local mode the BPA AGC system is disabled. The plant is not controlling its power output to meet generation request and generation rate of response originating from BPA.

2. When plant is in BPA kV mode, the coordinated var control system is enabled at the plant. The plant is controlling reactive power output to meet the voltage schedule originating from BPA. When the plant is in local kV mode, the BPA coordinated var control system is disabled at the plant but automatic voltage regulators are still in service. The plant is controlling its reactive power output to meet the nominal voltage schedule originating from BPA.

7-D. Generation and Network Interchange Scheduling Requirements

Any new load or generation being integrated into the BPA Grid must adhere to the scheduling requirements of the prevailing tariff under which it is taking transmission or control area service from BPA. Customers may be required to provide BPA Transmission Scheduling with an estimate of the their hourly load, hourly generation schedules, and/or net hourly interchange transactions. These estimates will be used for both pre-scheduling and planning purposes. BPA will require customers to provide these estimates as necessary in order for BPA to manage the load or resource balance within the BPA Control Area and to determine usage of the BPA Grid.

In the case of new transmission facilities, scheduling and accounting procedures are needed if the facility is part of an interface between the BPA Control Area and another control area. This scheduling and accounting of interchange between two control areas normally requires telemetered data from the POI to the control centers of the control area operators. This data is termed interchange metering and telemetering by BPA and includes kW and kWh quantities. BPA requires that all control area transactions be pre-scheduled for each hour using the normal scheduling procedures. The end-of-hour actual interchange must be conveyed each hour to the BPA Control Center(s). This can be accomplished through the use of telemetering or data link.

When the new interconnection represents a shared or jointly owned interface to BPA, or a split resource between the control area and any other, then a calculated allocation is usually required to divide up the total metered interchange. This non-physical interface is accomplished by dynamic signal. A two-way dynamic signal is required when a combined request and response interface is used. An example is supplemental AGC services. A one-way dynamic signal is required when a response (or following) interface is used. Moving a control area boundary is an example of this requirement.

7-D.1 Generation Metering Requirements

Generation metering usually consists of bi-directional meters and related communications systems providing active power (in kW) and energy (in kWh) from the POI. Active power is telemetered on a continuous basis for AGC and hourly energy is sent each hour to the control area accounting for BPA. All generation projects of aggregate size equaling or exceeding one MVA require hourly pre-scheduling. BPA may also require indication of available spinning reserve and controlled reserves, both in MW. (See section 7-F for more on reserves

a. Interchange Metering Requirements

Interchange telemetering generally consists of bi-directional meters and related telecommunications systems providing kW and kWh at or near the POI. The kW measurement is telemetered on a continuous basis for AGC and hourly kWh is sent each hour to the control center. (Tables 7-1, 2 and 4 summarize the requirements). Interchange telemetering accuracy and calibration requirements are identical with those stated in Sections 7-D and 4-F.

Effective telemetering requires real-time knowledge of the quality of measurement. Associated with the telemetering signal are various indications of this quality. Analog telemetering is commonly accompanied with squelch and telemetering carrier fail alarms. A loss of meter potential or meter potential phase unbalance should trigger a telemetering carrier failure alarm. Digital telemetering has equivalent signal failure alarms. The metering equipment must also be monitored and alarmed in the telemetering signal. Typical alarms include but are not limited to:

- Loss of meter potential
- Loss of telemetering signal
- Loss of meter potential signal

b. Generation Station Service and Start-Up Metering

If BPA supplies a generation site station service, then that station service must be properly and accurately metered. This may require separate dedicated meters for station service. It is preferred to meter generation by locating metering accuracy current transformers such that accurate station service can also be metered. Then net generation, start-up and station service can be accomplished from one-meter location. However, if this is not possible, then metering with demand interval data recording (MV90™ compatible) and communications would be required at the station service transformer(s). Meter data is recorded when BPA is supplying either transmission, energy or both.

7-E. Revenue and Interchange Metering System

All interconnections of facilities capable of exchanging at least 1 kW of active power require BPA qualified metering for revenue or interchange. Energy data recording is required for BPA's billing and scheduling functions. Revenue metering includes energy (kWh) and reactive power (kvarh) produced by revenue meters and recorded on a demand interval basis. Interchange metering includes bi-directional energy and reactive data as well as special telemetering requirements for scheduling purposes. The metering shall be located to measure the net power at the POI to or from the BPA Grid.

The revenue metering system (RMS) includes a remote metering system to record the hourly kWh data. The hourly kWh data is downloaded from the metering recorder on a daily basis over voice-grade telephone lines. All recorders must be fully compatible with the MV-90™ protocol. Demand data will be available to the customer or their agent.

BPA typically owns and maintains the revenue metering at load-metering sites. BPA will supply the Requester with a list of pre-qualified metering systems should the Requester desire to furnish, own or maintain the metering system. If the selected system is not on the BPA pre-qualified list, BPA reserves the right to perform a full set of acceptance tests, possibly at the Requester's expense, prior to granting permission to use the selected system

7-E.1 Requirements for Revenue and Interchange Metering

Three-element, three-phase, four-wire meters shall be used on grounded power systems. Two-element, three-phase, three-wire meters can be used on balanced, ungrounded power systems. Both revenue metering and interchange metering shall be bi-directional to record both active and reactive power flows to or from the POI. Metering packages include a kWh recording device compatible with the BPA RMS or BPA scheduling system, as applicable.

Should the new POI result in the addition of generation to the BPA Grid not previously accounted for, there will be additional metering requirements.

Tables 7-1 through 7-4 identify revenue metering requirements. Section 8-D discusses telecommunications requirements for the RMS system.

7-E.2 Required Accuracy of Meters

Watt-hour meters shall be calibrated to ±0.1% accuracy at unity power factor for both full load and light load. Watt-hour meters shall also be calibrated to ±0.3% accuracy for 0.5 power factor at full load. Var-hour meters shall have ±0.2% accuracy at unity power factor and ±0.6% accuracy at 0.5 power factor. Full load is defined as 100% meter current rating at nominal voltage. Light load is defined as 10% meter current rating at nominal voltage.

7-E.3 Instrument Transformers

Voltage and current instrument transformers shall be 0.3% accuracy class for both magnitude and phase angle over the burden range of the installed metering circuit. The instrument transformers shall be of a shielded design in order to prevent unintentional energization of the transformer secondary during a transformer failure. Instrument transformers for metering must be located such that the input to the metering and telemetering is not interrupted during possible switching configurations at the POI.

7-E.4 Loss Compensation

Transmission system losses, such as those in transformers, often must be accounted for in the revenue metering process. BPA prefers that this accounting be done as a calculated part of the BPA billing and settlement process.

7-E.5 Station Service Power

Depending upon its electrical source and electrical location, the station service power for the connecting substation facilities may also require revenue metering. It may not be necessary to meter station service var hours although most modern electronic meters include this feature as part of the meter.

7-F. Calibration of Metering, Telemetering, and Data Facilities

7-F.1 Revenue and Interchange Metering

Revenue and interchange metering needs to be calibrated at least every two years. More frequent calibration intervals may be negotiated. All parties to the transmission interconnection agreement may witness the calibration.

7-F.2 SCADA and ICCP Data

SCADA and ICCP data shall be calibrated every two years as a minimum or more often if significant errors occur affecting the state estimator results. All parties to the transmission interconnection agreement may witness the calibration.

8. Telecommunication Requirements

8-A. Introduction

Telecommunications facilities shall be installed to fulfill the control, protection, operation, dispatching, scheduling, and revenue metering requirements. They may be owned by BPA, another utility or a third party. At a minimum, telecommunications facilities must be compatible with, and have similar reliability and performance characteristics to, that currently used for operation of the power system to which the new generation or loads will be connected. Telecommunications facilities will be identified on the Project Requirements Diagram (PRD). Depending on the performance and reliability requirements of the control and metering systems to be supported, the facilities may consist of any or all of the following:

8-A.1 Radio Systems

A radio system requires transmitters, receivers, telecommunication fault alarm equipment, antennas, batteries, chargers, and multiplex equipment. It may also include buildings, towers, emergency power systems, mountaintop repeater stations and their associated land access rights, as needed to provide an unobstructed and reliable telecommunications path. In order to meet power system reliability requirements, radio path diversity, equipment redundancy or route redundancy may be required. These measures protect against telecommunications outages caused by equipment failure or atmospheric conditions.

8-A.2 Fiber Optic Systems

A fiber optic system requires light wave transmitters, receivers, telecommunication fault alarm equipment, multiplex equipment, batteries, chargers, emergency power systems, fiber optic cable (underground or overhead) and rights-of-way. Cable route redundancy may be required in order to prevent telecommunications outages caused by cable breaks.

8-A.3 Wireline Facilities

A wireline facility (e.g., leased line) requires telecommunications cable (underground or overhead), high-voltage isolation equipment, and rights-of-way. It may also include multiplex equipment, emergency power systems, and batteries, depending on the wireline technology employed. Cable route redundancy may be required in order to prevent telecommunications outage.

8-A.4 Power Line Carrier

A power line carrier current system uses the actual power line conductor(s) as the transmission media. Coupling capacitors, line tuning units and wave traps are used to connect the carrier transmitter and receiver to the power line. Power line carrier availability and performance is greatly affected by line outages.

8-B. Voice Communications

8-B.1 Basic Requirements

If the generation or load facility is within the BPA Control Area and any type of telemetering is required, then voice communications to the operator are also required. If the facility is not staffed with operators, alternative arrangements may be made subject to BPA approval.

8-B.2 Automatic Ringdown Trunks

Dedicated, direct automatic ringdown trunk (or equivalent) voice circuits between each appropriate BPA control center and the operator of the generators or loads may be required for:

- Generators or loads of 50 MW or greater,
- Eccentric (non-conforming) generators or loads
- Connected networks that include automatic generation dropping for BPA Transmission system remedial action.
- A non-radial interconnection to another electric utility with a transfer capability in either direction of 50 MW or greater.

8-B.3 Independent Communications

Independent voice communications for coordination of system protection, control and telecommunication maintenance activities between BPA and the generation facility or POI should also be provided.

8-C. Data Communications

Telecommunications for SCADA, RMS and telemetering must function at the full performance level before and after any power system fault condition. Repair personnel must restore service continuity immediately after the fault without the need for intervention. The following requirements for telemetering of data are specified:

8-C.1 SCADA

For communication of SCADA information, one or more dedicated circuits are typically required between a new facility and the appropriate BPA control center(s).

8-C.2 Automatic Generator Control (AGC) Interchange and Control Telemetering

One or more dedicated circuits are typically required between the new generation facility and the appropriate BPA control center(s) for telemetering of AGC Interchange and control information for operations and scheduling applications. If AGC services are required, data will be sent to and from the appropriate BPA control center(s) using the Inter-Control Center Communications Protocol (ICCP) over private control synchronous communication channels operating at a minimum rate of 9600 baud.

8-C.3 General Telemetering

General telemetering of power and energy data (in kW, kvar, kWh) and data acquisition systems typically require one or more dedicated communication circuits. These circuits link the new facility to the master computer receiving the data.

8-C.4 Revenue Metering System (RMS)

Commercial dial-up telephone exchange line facilities are required for support of the MV-90™ compatible remote RMS equipment. The exchange line facilities communicate with the MV-90™ compatible master computer at the Dittmer Control Center. The circuit used for this purpose may also be shared with voice communications and other dial-up data communications.

8-D. Telecommunications for Control and Protection

Telecommunications for control and protection must function at the full performance level before, during and after any power system fault condition. The delivery of a false trip or control signal, or the failure to deliver a valid trip signal is unacceptable. Active telecommunication circuits for control and protection must not be tested, switched, shorted, grounded or changed in any manner by any worker, unless prior arrangements have been made through the BPA dispatcher.

8-D.1 Application on Main Grid Transmission

The highest telecommunications performance level as specified by the WECC (ref 3.6) is 99.95% availability. This level of performance is required on all protection circuits for lines connected to the BPA Main Grid. This performance level is also required for RAS circuits that must meet WECC compliance criteria. These circuits require totally redundant schemes.

Availability is determined for the total path of the protective relaying circuit, from one end of the transmission line to the other. Options for achieving these availability requirements by utilizing two or more separate telecommunication methods, routes or systems may be considered. When alternately routed telecommunications for protective relaying schemes are required, a combination of two of these telecommunications methods may be used to meet availability requirements.

8-D.2 Non-Main Grid Transmission Applications

A telecommunications performance level of 99.5% (ref 3.6) is required for less critical protection circuits. This level of performance is also required for RAS circuits that do not have to meet the WECC criteria. Generally, redundant telecommunications systems are not required, except under certain circumstances in order to ensure the reliability and speed of the transmission of signals for protection and RAS.

8-D.3 Speed of Operation

Throughput operating times of the telecommunications system must not add unnecessary delay to the clearing or operating times of protection or RAS. System studies and WECC trip time requirements (ref 3.6) determine maximum permissible throughput operating times of control schemes.

8-D.4 Equipment Compatibility

Protection systems and supporting telecommunications equipment installed at the interconnecting facility must be functionally compatible or identical to the corresponding equipment employed at the BPA facility. This functionality need not extend to peripherals, such as signal counters and test switches that might be present on BPA's equipment. Teleprotection equipment employed by the Requester must be approved by BPA prior to installation. At the time of the request for interconnection BPA will supply the Requester with a list of acceptable, pre-qualified equipment. Should the Requester choose to employ equipment not on this list, BPA reserves the right to test the equipment for acceptable performance in the required control application. Equipment that passes this testing can be approved by BPA for subsequent installations.

Teleprotection systems, including transfer trip, must be properly designed and tested to demonstrate that they perform their intended functions. When applying digital telecommunications systems to protection schemes, care must be taken ensure equipment compatibility

8-E. Telecommunications During Emergency Conditions

8-E.1 Emergency Conditions

Emergency telecommunications conditions may develop that affect telecommunications equipment with or without directly affecting power transmission system facilities.

Examples of telecommunications emergencies include the following:

- Interruption of power to telecommunications repeater and relay stations
- Telecommunications equipment failure, whether minor or catastrophic
- Interruption or failure of commercial, public switched telephone network facilities or services
- Damage to telecommunications facilities resulting from accident, acts of vandalism, or natural causes

Equipment redundancy and telecommunications route redundancy can protect against certain kinds of failure and telecommunications path interruption. A repair team dedicated to the telecommunications of the interconnecting facility should be retained along with an adequate supply of spare components.

8-E.2 Backup Equipment

Where commercial, public telephone network facilities or services support important power system telecommunications, a backup strategy should always be developed by the Requester to protect against interruption of such services. Backup methods could include redundant services, self-healing services, multiple independent routes, carriers and combinations of independent facilities such as wireline and cellular, fiber and radio, etc. Backup telecommunications system equipment such as emergency standby power generators with ample on-site fuel storage and reserve storage battery capacity must be incorporated in critical telecommunications facilities. Backup equipment should also be considered for certain non-critical telecommunications to provide continued operation of telecommunications during interruption of transmission services.

8-E.3 Disaster Recovery

The Requester should have a disaster recovery plan in place for telecommunications restoration that should be exercised periodically. The disaster recovery plan should include the ability to provide equipment capable of bypassing or replacing entire telecommunication stations or major apparatus until permanent repairs can be made.

8-E.4 Telecommunications Security

The operation of power system telecommunications facilities should be continuously monitored at a central alarm point so that problems can be immediately reported, diagnosed and repaired. Telecommunication sites and facilities should be secured against unauthorized access.

9. Information Requirements for Generators

9-A Introduction

When a request is submitted for a connection to the BPA Grid certain information must be included so BPA can properly consider the interconnection request. The actual information required by BPA will vary depending upon the type of request. Requestors should contact a BPA Account Executive and refer to BPA Business Practices for application forms and procedures. This section describes typical information and data that BPA will require.

9-B Connection Location

BPA needs location information for the proposed interconnection in order to adequately study the impacts. Location information required will vary depending upon the proposal.

Locations of new substations, generators or new taps on existing lines must include the state, county, township, range, elevation, latitude and longitude. BPA also requires driving directions to the location for a site evaluation.

1. Identify the substation if connecting to an existing BPA substation.

2. If the connection is between two existing substations, the substations need to be identified.

3. For connection to an existing BPA transmission line, identify the line by name as well as the location of the proposed interconnection.

4. If the request includes a new substation or generator site, the proposed location is required.

9-C Electrical Data

The electrical data required will depend upon the type of connection requested.

9-C.1 Electrical One-Line Diagram

The electrical one-line diagram should include equipment ratings, equipment connections, transformer configuration, generator configuration and grounding, bus, circuit breaker and disconnect switch arrangements, etc.

9-C.2 Generator Data

If one or more generators are included as part of the connection request, the following data is needed. If different types of generators are included, data for each different type of generator and generator step up transformer is needed.

a. Generator General Specifications

1. Energy source (e.g., natural gas, coal, wind, hydro, co-generation, geothermal, etc.)

2. Number of rotating generators
3. Number of turbines, combustion, steam, wind, hydro, etc.
4. Total project output, MW, (@ 0.95 PF for synchronous generators)
5. Station service load for plant auxiliaries, kW, kvar
6. Station service connection plan

b. Generator Data, Synchronous Machines

Data for each different rotating-machine generator assembly generator, turbine, shaft is required. Also, provide the graphs and parameters for each type and size of specified generator as supporting technical documentation:

1. Reactive capability, 'P-Q' curves
2. Excitation 'Vee' curves
3. Saturation and synchronous impedance curves
4. Identifier (e.g., GTG #12)
5. Number of similar generators
6. Complex power, kVA
7. Active power, kW
8. Terminal voltage, kV
9. Machine parameters
   - *a.* S_b – Complex power base (MVA) upon which machine data is specified
   - *b.* H – Normalized rotational kinetic energy of the generator/turbine/shaft assembly, kW-sec/kVA
   - *c.* WR2 – Moment of inertia, lb. Ft^2
   - *d.* Ra – Armature resistance, pu
   - *e.* Xd – Direct axis unsaturated synchronous reactance, pu
   - *f.* X'd – Direct axis unsaturated transient reactance, pu
   - *g.* X'q – Quadrature axis saturated and unsaturated transient reactance, pu
   - *h.* X"d – Direct axis saturated and unsaturated subtransient reactance, pu
   - *i.* XI – Stator leakage reactance, pu
   - *j.* X2 – Negative-sequence reactance, pu
   - *k.* X0 – Zero-sequence reactance, pu
   - *l.* Xn – Zero-sequence unit grounding reactance, pu
   - *m.* Rn – Zero-sequence unit grounding resistance, pu
   - *n.* T'do – Direct axis transient open circuit time constant, seconds
   - *o.* T'qo – Quadrature axis transient open circuit time constant, seconds
   - *p.* T"do – Direct axis subtransient open circuit time constant, seconds
   - *q.* T"qo – Quadrature axis subtransient open circuit time constant, seconds
   - *r.* S(1.0) – Saturation factor at rated terminal voltage, A/A
   - *r* S(1.2) – Saturation factor at 1.2 per unit of rated terminal voltage, A/A

10. Excitation system modeling information
    - *a.* Type (static, ac rotating, etc.)
    - *b.* Maximum/Minimum dc current

c. Maximum/Minimum de voltage
d. Nameplate information
e. Block diagram
f. Power System Stabilizer (PSS) type and characteristics

11. Speed governor information with detailed modeling information for each type of turbine.
    a. Turbine type (Combustion, Steam, Wind, Hydro)
    b. Total capability, MW (available peak operation rating)
    c. Number of stages
    d. Manufacturer and model, if known
    e. Frequency vs. time operational limits, seconds at Hz
    f. Maximum turbine ramping rates, MW/minute, ramp up and ramp down

c. Generator Data, Asynchronous Machines

1. Shunt reactive devices (capacitor banks) for power factor correction with induction generators or converters.
    a. PF without compensation
    b. PF with full compensation
    c. Reactive power of total internal shunt compensation voltage, kvar

2. AC/DC Converter devices employed with certain types of induction-motor installations or with dc sources.
    a. Number of converters
    b. Nominal ac voltage, kV
    c. Capability to supply or absorb reactive power, kvar
    d. Converter manufacturer, model name, number, version
    e. Rated/Limitation on Fault current contribution, kA

3. Machine parameters
    a. S_b – Complex power base (MVA) upon which machine data is specified
    b. H – Normalized rotational kinetic energy of the generator/turbine/shaft assembly, seconds
    c. Ra – Armature resistance, pu
    d. Xd – Direct axis saturated and unsaturated synchronous reactance, pu
    e. X'd – Direct axis saturated and unsaturated transient reactance, pu
    f. X"d – Direct axis saturated and unsaturated subtransient reactance, pu
    g. XI – Stator leakage reactance, pu
    h. X2 – Negative-sequence reactance, pu
    i. X0 – Zero-sequence reactance, pu
    j. Xn – Zero-sequence unit grounding reactance, pu
    k. Rn – Zero-sequence unit grounding resistance, pu
    l. T'do – Direct axis transient open circuit time constant, seconds
    m. T"do – Direct axis subtransient open circuit time constant, seconds
    n. S(1.0) – Saturation factor at rated terminal voltage, A/A

o. S(1.2) – Saturation factor at 1.2 per unit of rated terminal voltage, A/A
p. Vt – Voltage threshold for tripping, pu
q. Vr – Voltage at which reconnection is permitted, pu
r. Tv – Pickup time for voltage-based tripping, seconds
s. Tvr – Time delay for reconnection, seconds
t. Ft – Frequency threshold for tripping, Hz
u. Tf – Pickup time for frequency-based tripping, seconds
v. Reactive power required at no load, kvar
w. Reactive power required at full load, kvar

4. External Shunt Compensation
   a. Bus Voltage
   b. Number and rating of each shunt capacitor section
   c. Voltage/PF controller scheme description and time delays

d. DC Sources

If the generator project includes dc sources such as fuel cells or photovoltaic devices, the number of dc sources and maximum dc power production per source, kW, is needed.

9-C.3 Load Information Requirements

If a new load or point of delivery is requested, the following information will generally be required.

1. Type of load, such as industrial, commercial, residential or combination
2. Load data
   a. Delivery voltage, kV
   b. Projected peak load, kW
   c. Summer peak load, kW
   d. Winter peak load, kW
   e. Anticipated power factor

9-C.4 Transformer Data

If one or more power transformers are included as part of the proposed connection, the following data is required for each unique transformer.

1. Transformer number or identifier
2. Number of similar transformers
3. Transformer type and number of windings, (e.g. Autotransformer, two winding)
4. Transformer winding data. For a two winding transformer, only winding H and X data is required.
   a. For each winding, H, X, y:
      1) Nominal voltage, kV
      2) Configuration (Δ or Y) and Y winding connection (ungrounded, solid ground or impedance ground)

   b. Transformer MVA ratings:
      1) Winding H to X, MVA
      2) Winding H to Y, MVA
      3) Winding X to Y, MVA

c. Transformer impedances, positive and zero sequence:
1) Winding H to X, % X and R at MVA
2) Winding H to Y, % X and R at MVA
3) Winding X to Y, % X and R at MVA

d. Transformer tap changer information
1) No load or load
2) Tap changer winding location, H, X, Y
3) Available taps

e. Transformer cooling requirements if required from BPA
1) Load, amps
2) Voltage, single or three phase, volts

9-C.5 Transmission Line Data

If a new transmission line is to be included as part of the proposed connection, the following transmission line data is required:

1. Nominal operating voltage, kV
2. Line length, miles
3. Line capacity, amps at ºC
4. Overhead/underground construction
5. Positive and zero sequence transmission line characteristics in primary values
   1) Series resistance, R Ω
   2) Series reactance, X Ω
   3) Shunt susceptance, B µ S (or µ Ω^{-1})

10. Definitions

For industry standard definitions of electric industry terminology, please refer to:
The Authoritative Dictionary of IEEE Standards Terms, IEEE 100.

For Bonneville Power definitions of electric utility terminology, please refer to:
BPA Definitions, available through BPA's Document Request Line (800) 622-4520 or www.bpa.gov/corporate/kcc/defn/starttx.shtml

For the purposes of this document the following definitions apply:

Active Power - The 'real' component of complex power carried by an alternating-current circuit, produced by mutually-in-phase components of voltage and current waveforms. Active power can be calculated as the product of apparent power and the power factor. Measured in units of watts (W), kW or MW, active power is associated with useful work, including mechanical work and heat. Active power used or transmitted over time is energy, measured in kilowatt-hours (kWh) or megawatt-hours (MWh.). Also known as 'real power'. See also 'power factor'.

Ancillary Services - The term used by FERC to describe the special services that must be exchanged among generation resources, load customers and transmission providers to operate the system in a reliable fashion and allow separation of generation, transmission and distribution functions. These include: 1) scheduling, system control and dispatching, 2) reactive power supply and voltage control from generators, 3) regulation and frequency response, 4) energy imbalance, 5) spinning reserves, and 6) supplemental reserves. Most of these services are included in a similar set by NERC and termed Interconnected Operations Services, which also include load following and black start capability.

__WECC Definition:__ Interconnected Operations Services identified by the U.S. Federal Energy Regulatory Commission (Order No. 888 issued April 24, 1996) as necessary to affect a transfer of electricity between purchasing and selling entities and which a transmission provider must include in an open access transmission tariff.

Area Control Error (ACE) – Area Control Error (ACE) is the instantaneous difference between net actual and scheduled interchange, taking into account the effects of frequency bias including a correction for meter error.

Automatic Generation Control (AGC) System – A system that measures instantaneous loads at interchange points (boundaries with adjacent control area) and adjusts generation to follow load. It consists of continuous, real time load signals (kW), telemetered to AGC computers at a transmission control center.

__NERC Definition:__ Equipment which automatically adjusts a control area's generation from a central location to maintain its interchange Schedule Plus frequency bias.

Blackstart Capability - The ability of a generating plant to start its unit(s) with no external source of electric power. *(WECC definition)*

BPA Dispatcher - The BPA Dispatcher or system operator is the ultimate authority on all operations, switching, etc. that can affect the BPA Grid. The BPA Dispatchers work 24/7 in two control centers located at Mead and Vancouver, Washington.

BPA Grid - The transmission facilities owned or controlled by Bonneville Power Administration's Transmission Business Line (BPA).

Control Area - 1. The electrical (not necessarily geographical) area within which a controlling utility has the responsibility to adjust its generation to match internal load and power flow across interchange boundaries to other control areas. 2. A resource or portion of a resource that is scheduled by a specific utility. If the utility schedules the resource, the resource becomes part of its control area. Physical location of the connection point does not determine its control area.

> ***WECC Definition**: An area comprised of an electric system or systems, bounded by interconnection metering and telemetry, capable of controlling generation to maintain its interchange schedule with other control areas, and contributing to frequency regulation of the interconnection.*

Coordinated Voltage Control (CVC) - Using AGC data links to the power plant, BPA will request a power plant to deviate from the published time-of-day high side bus voltage schedule to coordinate closely coupled power plants to operate at the same power factor. By minimizing circulating var flow between power plants, all power plants will minimize their var production requirements. The CVC program runs once every two-minutes. It is a slow adjustment of voltage schedules and is not intended to replace the function of the automatic voltage regulator. Closely coupled power plants are determined by incrementing and decrementing the bus voltages 0.01 pu in a power flow study. Plants that show significant response by a change in var production are considered closely coupled. Examples include: Chief Joseph and Grand Coulee 230 kV and 500 kV; Centralia and Big Hannaford and Chehalis 500 kV; John Day and Boardman and Coyote Springs and Calpine Hermiston 500 kV and McNary and US Gen 230 kV.

Directional Relay - A relay that responds to the relative phase position of a current with respect to another current or voltage reference, with the intent of distinguishing the direction of the fault location.

Distribution - That part of the electric grid associated with delivery of energy to customers. Distribution-level nominal voltages are generally considered to be 34.5 kV or lower. The set of distribution facilities owned, leased, or operated by BPA is not extensive.

Disturbance - An unplanned event that produces an abnormal system condition. *(WECC definition)* The most common disturbances are: (a) faults with subsequent tripping of a transmission line or distribution feeder and (b) loss of a generator with subsequent temporary system frequency decrease.

Dynamic Signal - A telemetered reading or value that is updated in real time, and which is used either as a tie line flow or as a schedule in the AGC/ACE equation (depending on the particular circumstances). Common applications of dynamic signals include 'scheduling' jointly owned generation to or from another control area and to move control area boundaries. Another application provides for an entity to request (schedule) a change in power flow. The resulting response is telemetered to the entity signifying the actual movement of a resource. This form of dynamic signal is applied to supplemental control area services. The integrated value of this signal is used for interchange accounting purposes, as appropriate.

Eccentric (Non-Conforming) Loads - Any cyclic load with the ability to change periodically by more than 50MW at a rate of greater than 50MW per minute, regardless of the duration of this change.

Effectively Grounded - A system that provides an $X_0/X_1<3$ & $R_0/X_1<1$ where X_0 and R_0 are zero sequence reactance and resistance respectively, and X_1 is positive sequence reactance.

Fault - A short circuit on an electrical transmission or distribution system between phases or between phases(s) and ground, characterized by high currents and low voltages.

Feeder - A radial electrical circuit, generally operating at or below 69 kV serving one or more customers.

FERC – Federal Energy Regulatory Commission On-line at www.ferc.gov.

Ferroresonance - A phenomenon usually characterized by overvoltages and very irregular wave shapes and associated with the excitation of one or more saturable inductors through capacitance in series with the inductor. (*IEEE definition*). A condition of sustained waveform distortion and overvoltages created when a relatively weak source of voltage energizes the combination of capacitance and saturable transformers. A sufficient amount of damping, or resistance, in the circuit usually controls or eliminates the phenomenon.

Generation Site - The geographical location of the Project generator(s) and local generator equipment. This may be near or far from either the Point of Interconnection or the Interconnecting Substation.

Harmonic – A sinusoidal component of a periodic wave or quantity having a frequency that is an integer multiple of the fundamental frequency. *(IEEE definition)* Harmonics can damage equipment, cause misoperation of relays, and can interfere with communications. Thus, they are an important aspect of power quality, and must be controlled by filtering or other methods.

Host Control Area - A control area that is operated by an authority other than BPA which does not overlap with the BPA Control Area.

Hybrid Single Pole Switching - A variation of single-pole switching that is used on long lines to extinguish the secondary arc of single line-to-ground faults. The faulted phase is detected and opened first via single-pole relaying. After approximately fifty cycles the two unfaulted phases are opened to extinguish the secondary arc. Three-phase automatic reclosing follows.

IEEE - Institute of Electrical and Electronic Engineers

Interchange Metering - Metering at interchange points between two controlling utilities, consisting of AGC (continuous kW) telemetering and hourly kWh (on-the-hour hourly load kWh). These quantities must go to both controlling utilities so they can manage their respective control areas.

Interchange Point - Locations where power flows from one control area to another (i.e. connection between two controlling utilities).

Inter-Control Center Communications Protocol (ICCP) - Inter-Control Center Communication Protocol (ICCP) is an international standard communications protocol for real time data exchange. The ICCP is defined in the international standard IEC 870-6 TASE.2.

Island - A portion of an interconnected system that has become isolated due to the tripping of transmission system elements. A local island is a portion of the transmission system, often a single line, that is isolated from the main system and energized by a local generator.

Main Grid - BPA's Main Grid transmission facilities include all 500 kV lines, 345 kV lines, as well as some lower voltage lines and supporting facilities (e.g., transformers) that carry bulk power within the Northwest. Main grid lines and equipment include the most critical equipment to the reliability of the BPA Grid.

MV-90™ - The Multi-Vendor Translation System interprets a variety of metering communication protocols used for data collection and analysis. Data is retrieved over dial-up (voice grade) telephone lines by the MV-90™ master located at the BPA Control Center. The master automatically polls the remotes daily can be used to poll a remote at any time. In addition to polling raw impulses from the recorders, MV-90™ can perform data validation, editing, reporting and historical database functions.

NERC - North American Electric Reliability Council is a not-for-profit corporation formed by the electric utility industry in 1968 to promote the reliability of the electricity supply in North America. NERC consists of 10 Regional Reliability Councils, one of which is the Western Electricity Coordinating Council. On-line at *www.nerc.com* .

OASIS – Open Access Same-Time Information System is an electronic posting system for transmission access data that allows all transmission customers to view the data simultaneously.

Phase Unbalance - The percent deviation of voltage or current magnitude in one phase as compared to the mean average of all three phases.

Pilot Protection (Pilot Telecommunications) – A communications signal between two protective relay terminals used to provide a trip signal between terminals. The communication channel may be power line carrier, microwave (or other radio-based) path, fiber optic circuit, leased telephone line, or a dedicated hardwire circuit.

Point of Interconnection (POI) - The physical location on the power system at which Requester-owned facilities connect to those owned by BPA, defining the 'change of ownership.

Power Factor - The dimensionless ratio of active power to apparent power in an alternating-current (ac) circuit. The power factor can range only between unity (with voltage and current mutually in phase), and zero (with voltage and current 90 electrical degrees mutually out of phase). A condition of 'lagging' power factor occurs when active power and reactive power propagate in the same direction – e.g., with inductive loads, which always consume reactive power; or with generators, when delivering reactive power. A condition of 'leading' power factor occurs when active power and reactive power propagate in opposite directions – e.g., with capacitive loads, which always delivers reactive power; or with generators, when consuming reactive power. For generators, operation with a lagging power factor is called an 'overexcited' condition; a leading power factor implies 'under excited' operation. Power factor is the cosine of the electrical angle between the voltage and current.

Power System – Integrated electrical power generation, transmission and distribution facilities.

Power System Stabilizer (PSS) - A device that provides an additional input to the exciter of a generator to provide damping of power system oscillations and improve system stability.

Project – Non-BPA owned facilities included in the interconnection request.

Project Requirements Diagram (PRD) - A BPA simplified drawing showing the electrical requirements for the connection of a generator, a transmission line or a load to the BPA Grid. The PRD consists of one or more pages that may include a connection diagram of the 60 Hz high voltage equipment, telecommunications and data requirements, and remedial action scheme (RAS) requirements.

Reactive Power - The 'imaginary' component of complex power carried by an alternating-current circuit, produced by components of voltage and current waveforms that are mutually out of phase by 90 electrical degrees. Reactive power can be calculated as the product of apparent power and the sine of the power factor angle. Measured in units of volt-amperes reactive (var), kvar or Mvar, reactive power is associated with the alternating exchange of stored energy between electric and magnetic fields. Although reactive power does no useful work, it is inherently required for operating any alternating-current power system or HVDC converter. By convention, reactive power is absorbed or consumed by an inductance and generated or produced by a capacitance. Reactive power transmitted over time is measured in var-hours (varh). See also 'power factor'.

Real Power – See 'Active Power'.

Real-Time - Data reported as it happens, with reporting (update) intervals no longer than a few seconds. Real-time applies to AGC type data, but not to kWh or RMS data, which are accumulated and reported only when queried by a master station.

Remedial Action Scheme (RAS) - A protection system that automatically initiates one or more control actions following electrical disturbances. Also referred to as 'Special Protection System.' Typical examples include tripping generators or loads and switching of series capacitors, shunt capacitors or shunt reactors.

Requester - An electrical utility or other customer or their representative that is requesting a new connection to the BPA Grid.

<u>Reserve</u> - *(WECC definitions)*

Operating Reserve - That reserve above firm system load capable of providing for regulation within the hour to cover load variations and power supply reductions. It consists of spinning reserve and non-spinning reserve.
Spinning Reserve – Unloaded generation which is synchronized and ready to serve additional demand. It consists of Regulating Reserve and Contingency Reserve.

Regulating Reserve – An amount of operating reserve sufficient to reduce Area Control Error to aero in ten minutes following loss of generating capacity, which would result from the most severe single contingency. At least 50% of this operating reserve shall be Spinning Reserve, which would automatically respond to frequency deviation.

Nonspinning Reserve – That operating reserve not connected to the system but capable of serving demand within ten minutes, or interruptible load that can be removed from the system within ten minutes.

Revenue Metering - General term for metering which is calibrated to ANSI Standards for Billing Accuracy.

Revenue Metering System (RMS) - Provides hourly data daily (as compared to kWh system that reports hourly load each hour). A meter and recording device are installed at points where billing quality data is required. The device meters kW and kVAr (bi-directional for Points of Interconnection) and records kWh and kVArh data on an hourly basis. Data is retrieved over dial-up (voice grade) telephone lines by the MV-90™ system located at Dittmer Control Center. The MV-90™ system automatically polls the device every morning beginning at 0001 am. The MV-90™ system can also other times to poll a remote at

Single Pole Switching – The practice of tripping and reclosing one phase of a three phase transmission line without tripping the remaining phases. Tripping is initiated by protective relays that respond selectively to the faulted phase. Circuit breakers used for single pole switching must be capable of independent phase opening. For faults involving more than one phase, all three phases are tripped. The purpose of single pole switching is to improve system stability by keeping two of the three transmission line phases energized and carrying power while the fault and secondary arc are removed from the faulted phase. See also 'hybrid single pole switching'

Station Service - The electric supply for the ancillary equipment used to operate a generating station or substation. *(NERC definition)* Generally, main grid substations require two sources of station service for reliability.

Supervisory Control and Data Acquisition (SCADA) - A system of remote control and telemetering used to monitor and control the transmission system. *(NERC definition)*

Tap Line – A line that connects to an existing transmission or distribution line without breakers at the tap point, resulting in an additional terminal on the existing line. The connection point may or may not include disconnect switches for isolation of one or all terminals.

Telemetering - Continuous, real time data reporting, as for AGC and generation kW (but not for kWh or RMS systems, which are not continuously reported).

> ***NERC Definition*** *- The process by which measurable electrical quantities from substations and generating stations are instantaneously transmitted using telecommunication techniques.*

Transmission – That part of the electric grid associated with bulk transfer of energy, at high nominal voltages (generally defined as 115 kV or above). BPA owns and operates transmission facilities at voltages of 500, 345, 287, 230, 161, 138 and 115. of BPA's 345 kV- and 287-kV transmission is on lines that are transformer-terminated at both ends.

Transformers and Transformer Connections – Large three-phase power transformers can be constructed using separate windings, as autotransformers or a combination of these. Transformers can use one tank for each phase or have all three phases in a single tank. The external winding connections can be delta (Δ) or grounded wye (YG), creating winding combinations such as Δ - YG, YG - YG, YG - Δ – YG.

Autotransformer: Transformer construction using a single coil where the lower voltage or 'winding' is created by simply tapping that coil at the desired voltage level, creating a metallic connection between the two windings. This is the typical construction used to transform voltages at transmission levels and uses a YG, three-phase connection (e.g. 525:230 kV, 230:115kV).

Separate windings: Transformer construction where the higher and lower voltage windings are individual coils, only coupled by a magnetic field. This is the typical construction used to transform voltages from transmission to distribution levels and for generator step-up transformers (e.g. 115:12.5 kV, 22:230kV).

Wye (Y) connection: Transformer connections where one end of each winding of the three phases is connected to a common point and then typically grounded (YG), possibly through an impedance.

Delta (Δ) connection: Transformer connections where one end of each winding of the three phases is connected to the next phase, creating a closed loop of windings with no connections to a common point.

WECC - Western Electricity Coordinating Council, is the reliability region to which BPA's control area belongs. WECC was formed on April 22, 2002 by the merger of the former Western Systems Coordinating Council (WSCC), Western Regional Transmission Association (WRTA), and Southwestern Regional Transmission Association (SRTA). WECC set and enforces reliability standards for operating and planning the bulk electric system in the region. On-line at *www.wecc.biz* .

11. References

1. Bonneville Power Administration - United States and Other Codes
   - 1.1 *BPA Definitions*, - DOE/BP 2279
   - 1.2 *Accident Prevention Manual* (APM) - DOE/BP I-0212
   - 1.3 *Reliability Criteria and Standards* - DOE/BP I-9113
   - 1.4 *AGC Requirements Document (BPA)*
   - 1.5 *National Environmental Policy Act* - 42 U.S.C. & 4321 et seq.
   - *1.6 Uniform Building Code*
   - *1.7 Occupational Safety and Health Administration*
   - *1.8 Open Access Transmission Tariff – DOE/BPA-3406 October 2001*

2. **ANSI – IEEE - NFPA**
   - 2.1 **IEEE Std 80** - *Guide for Safety in AC Substation Grounding*
   - 2.2 **ANSI/IEEE Std 81 Part 1** - *Guide for Measuring Earth Resistivity, Ground Impedance, and Earth Surface Potentials of a Ground System* & Part 2: *Guide for Measurement of Impedance and Safety Characteristics of Large, Extended or Interconnected Grounding Systems*
   - 2.3 **IEEE 100** – *The Authoritative Dictionary of IEEE Standards Terms*
   - 2.4 **IEEE Std 367** - *Recommended Practice for Determining the Electric Power Station Ground Potential Rise and Induced Voltage from a Power Fault*
   - 2.5 **ANSI/IEEE Std 421.1** – *IEEE Standard Definitions for Excitation Systems for Synchronous Machines*
   - 2.6 **IEEE Std 421.2** – *IEEE Guide for Identification, Testing, and Evaluation of the Dynamic Performance of Excitation Control Systems*
   - 2.7 **IEEE Std 487** - *Recommended Practice for the Protection of Wire-Line Communication Facilities Serving Electric Power Stations*
   - 2.8 **IEEE Std 519** - *IEEE Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems*
   - 2.9 **IEEE Std - 837** - *Standard for Qualifying Permanent Connections Used in Substation Grounding*
   - 2.10 **IEEE Std – 1159** – *Recommended Practice for Monitoring Electric Power Quality*
   - 2.11 **IEEE Std – 1547** – *Interconnecting Distributed Resources with Electric Power Systems*
   - 2.12 **IEEE Std – C37.118** – *Enclosed Field Discharge Circuit Breakers for Rotating Electric Machinery*
   - 2.13 **IEEE Std, C57.116**, *Guide for Transformers Directly Connected to Generators*
   - 2.14 **NESC C2** - *National Electrical Safety Code*
   - 2.15 **ANSI C84.1** – *Electric Power System and Equipment – Voltage Ratings (60 Hz)*
   - 2.16 **NFPA 70** - *National Electrical Code*
   - 2.17 **IEC 870-6 TASE.2** - *Inter-Control Center Communication Protocol (ICCP) Standard.*

3. **NERC – NWPP - WECC**
   - 3.1 NERC *Operating Standards*
   - 3.2 NERC/WECC *Planning Standards*
   - 3.3 NWPP *Operating Manual*
   - 3.4 NERC/WECC *Reliability Criteria* including:
     - 3.4.1 *Reliability Criteria for System Design*
     - 3.4.2 *Power Supply Design Criteria*

3.4.3 *Minimum Operating Reliability Criteria*.
3.4.4 *Reliability Management System*

3.5 WECC Procedure for *Coordination of Scheduled Outages and Notification of Forced Outages*

3.5.1 Dispatcher/System Operator Handbook

3.6 WECC *Communications Systems Performance Guide for Protective Relaying Applications*

BPA F6420.25

U.S. DEPARTMENT OF ENERGY
BONNEVILLE POWER ADMINISTRATION
TRANSMISSION BUSINESS LINE

Electronic Form

TRANSMISSION LINES AND LOADS CONNECTION INFORMATION
APPENDIX A

WHO SHOULD FILE THIS FORM:
Any customer expressing an interest in connecting transmission lines or loads to BPA TBL's Transmission System. This application should be completed as soon as possible and returned to the BPA Transmission Account Executive in order to begin processing the

INFORMATION:
This application will be used by the Bonneville Power Administration to determine if a System Impact and Facility Requirement Study is required. This study is used to determine the location (Connection Point), equipment requirements (Requester & BPA TBL), system modifications, etc. to connect transmission lines and/or loads. Sections 1 and 2 should be completed as soon as possible and returned to the BPA Transmission Account Executive. Section 3 must be completed if it is determined that a System Impact and Facility Requirement Study is required. Following completion of the study the Requester will receive a preliminary estimate for the utility interface requirements that may be used in calculating the overall project connection requirements.

SECTION 1 - INTERCONNECTION REQUESTER AND CONTRACTORS

REQUESTER/OWNER INFORMATION

Company

Mailing Address

City | State | 9 Digit Zip Code

Phone Number | Email Contact

CONNECTION DESIGN/ENGINEERING ARCHITECT *(As applicable)*

Company

Mailing Address

City | State | 9 Digit Zip Code

Phone Number | Email Contact

ELECTRICAL CONTRACTOR *(As applicable)*

Company

Mailing Address

City | State | 9 Digit Zip Code

Phone Number | Email Contact

SECTION 2 - GENERAL SPECIFICATIONS, LOCATION, AND DIAGRAMS FOR CONNECTION

Preliminary Review Information

1. Type of Connection

Radial Lo☐d Network ☐nnection with Other Sources Present

Operating Voltage: ______________kV

Comments:

2. Connection Point Location

State	County	Nearest community
Township	Range	Section

Street address

Identify the BPA TBL Line or Substation Connection Point:

3. Type of Load

Identify the characteristics which best describe the type of load to be served.

More specific information may be required for loads such as those associated with arc furnaces, large motor, etc.

4. Load Data (at the time of energization and every year for 10 years)

Projected Peak Load (kW)

Summer Peak Load (kW)

Winter Peak Load (kW)

Anticipated Power Factor

5. Quality of Service (Special Requirements such as power quality, frequency and duration of outages, etc.)

6. Future Plans (Where known)

Modification, changes, or additions affecting the connection or connected equipment

7. Attach Electrical One-Line Diagram of the project that includes proposed protective relaying, breaker and switching arrangements, ground sources (zero sequence), and assumed electrical equipment parameters for the connection.

DATE	**SIGNATURE**
NAME *(Please Print or Type)*	**TITLE**

SECTION 3 - STUDY DATA REQUIREMENTS

1. Network Power Flow Model (as required)
Enclose a model using approved WECC format

2. Interconnecting Transmission Line(s) or Cable (provide all parameters in physical units if applicable:)

Nominal voltage [kV] Length [miles]

Transmission Line Impedances

Quantity	Positive Sequence	Zero Sequence
Series Resistance, R Ω		
Series Reactance, X Ω		
Shunt Susceptance, B μ S (or $\mu\Omega^{-1}$)]		

Will this line be built on common structures with other circuits? *(yes or no)* [ ]

Will this line be transformer-terminated at either end? If "yes", state which end(s) and the transformer identifier: [ ]

3. Transformers (provide parameters if applicable)

Identifier: [ ] Number of Windings *(2 or 3)* [ ] Autotransformer? *(Yes or No)* [ ]

Winding ("H"): Nominal Voltage [kV] Configuration (Δ or YG) [ ] Nameplate MVA, H to X [/ /]

Winding ("X"): Nominal Voltage [kV] Configuration (Δ or YG) [ ] Nameplate MVA, H to Y [/ /]

Winding ("Y"): Nominal Voltage [kV] Configuration (Δ or YG) [ ] Nameplate MVA , X to Y [/ /]

Tap Information: Winding (H, X, or Y) [ ] Values: Operational [kV] Available Taps (kV)[/ / / / / /

Transformer Impedance: Winding H to X: [% @ MVA] H to Y: [% @ MVA] X to Y: [% @ MVA]

4. System Data (only applicable where generation resources are present or if the connection includes another network source.)
Provide a system equivalent (R1,X1,R0,X0 in per unit on a 100 MVA base) at the proposed Connection Point looking into the connecting system. This values should be determined such that the system model *does not* include the physical connection to the BPA System. Assuming there are no other connections to the BPA System at any other point, these quantities are available by computing a single line-to-ground 'bus fault' at the proposed Connection Point.

Generation (if applicable)
(Must follow the processes as described in this BPA document that are appropriate for a new generation interconnection.)

5. Reactive Equipment (Location, size, and rated voltage)

More specific information is required for reactive with dynamic capability (SVC, TCSC, Sync Condensers, etc.)

To be filled out by the BPA Transmission Account Executive:

Transmission Account Executive	Region
Internal Routing	Phone Number

Copy of Interconnection Study Request and Attachments to:

Transmission Planning Manager – TOP
System Protection Manager - TNC
Customer Service Engineering – TOC